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Volume I. Technical Discussion

TRW Environmental Engineering Div, Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, NC

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Volume I.
Technical Discussion

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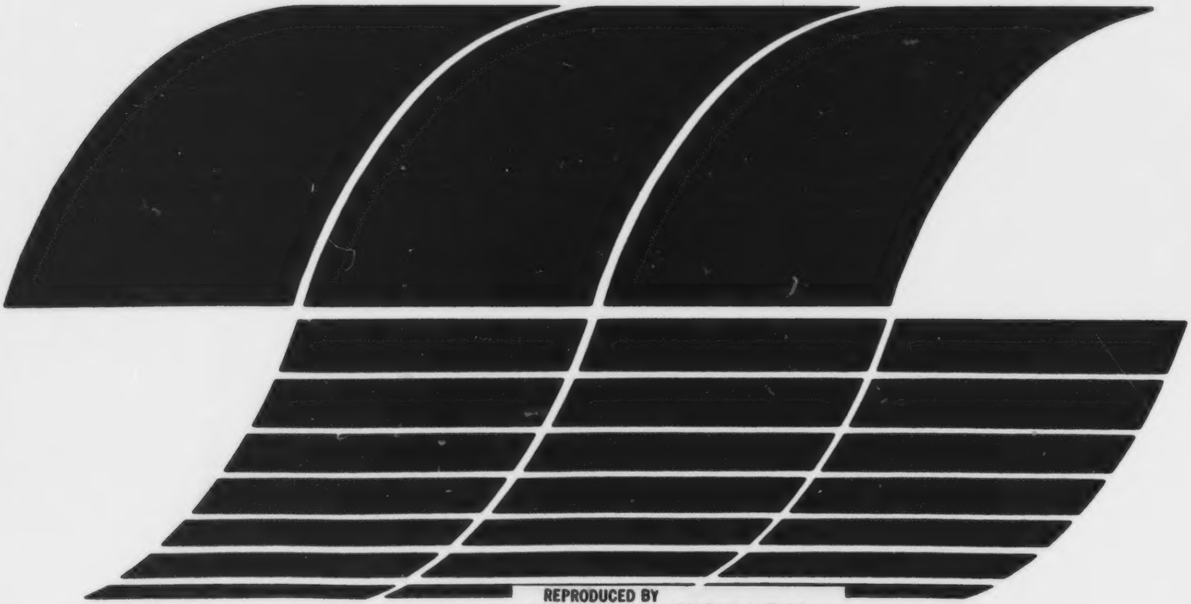

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16. ABSTRACT

The report is part of a comprehensive EPA program for the environmental assessment (EA) of high-Btu gasification technology. It summarizes and analyzes the existing data base for the EA of technology and identifies limitations of available data. Results of the data base analysis indicate that there currently are insufficient data for comprehensive EA. The data are limited since: (1) there are no integrated plants, (2) some of the pilot plant data are not applicable to commercial operations, (3) available pilot plant data are generally not very comprehensive in that not all streams and constitutents/parameters of environmental interest are addressed, (4) there is a lack of experience with control processes/equipment in high-Btu gasification service, and (5) toxicological and ecological implications of constituents in high-Btu gasification waste streams are not established. A number of programs are currently under way or planned which should generate some of the needed data. The report consists of three volumes: Volume I summarizes and analyzes the data base; Volume II contains data sheets on gasification, gas purification, and gas upgrading; and Volume III contains data sheets on air and water pollution control and on solid waste management.

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Environmental Assessment Data Base for High-Btu Gasification Technology:

Volume I. Technical Discussion

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ABSTRACT

This report has been prepared as part of a comprehensive program for the environmental assessment of high Btu gasification technology. The program is being directed by the Fuel Process Branch of EPA's Industrial Environmental Research Laboratory, Research Triangle Park, N.C. This document summarizes and analyzes the existing data base for the environmental assessment of the subject technology and identifies limitations of the available data.

To enable systematic data analysis, high Btu gasification technology was divided into a number of operations and auxiliary processes. These were further subdivided/grouped into a number of process modules. Data sheets were prepared for individual processes in a module presenting key process information, input and waste stream characteristics and gaps in the existing data. Where applicable, the data sheets were sent to process developers/licensors and technical experts for review. Each process was evaluated for applicability to high Btu gasification. Gas treatment and pollution control options in integrated commercial SNG facilities were examined.

The results of the data base analysis indicate that there currently are insufficient data for comprehensive environmental assessment. The data are limited since (1) there are no integrated plants, (2) some of the pilot plant data are not applicable to commercial operations, (3) the available pilot plant data are generally not very comprehensive in that not all streams and constituents/parameters of environmental interest are addressed, (4) there is a lack of experience with control processes/equipment in high Btu gasification service, and (5) toxicological and ecological implications of constituents in high Btu gasification waste streams are not established. A number of programs are currently under way or planned which should generate some of the needed data.

This report consists of three volumes. Volume I presents the summary and analysis of the data base; Volumes II and III contain the "data sheets."

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1.0 INTRODUCTION

1.1 BACKGROUND

The recognition of the limited availability of the domestic supplies of natural gas and crude oil and the desire to reduce the country's dependence on foreign sources of energy have promoted considerable interest in this country in developing alternative domestic sources of fuel. Because of the abundance of mineable coal reserves in the U.S., the greater use of coal, directly or after conversion to substitute natural gas (SNG) or oil products, is receiving increasing emphasis. Although coal can be substituted for natural gas and petroleum for industrial and utility steam and power generation, for technical and economic reasons coal cannot replace oil and gas in applications such as residential heating and transportation. Even if coal could be substituted for oil and gas, in certain applications such substitution can present enormous pollution control problems. For example, it would be very difficult and costly to install, operate and maintain pollution control systems on large numbers of small and scattered residential and commercial furnaces. Coal can be converted to clean liquid and gaseous fuel which can then be conveniently substituted for natural gas and petroleum products without requiring end use equipment modification or pollution control. From the standpoint of storage and transportation, the use of SNG and coal-derived liquid fuels also offers advantages over direct coal utilization since the existing gas and oil pipeline and truck and rail distribution systems can be utilized without major modifications. Because of the potential benefits associated with the conversion of coal to synthetic fuels, a number of programs, sponsored by both the government and private industry and aimed at developing new conversion technologies and improving and/or commercializing the existing ones for domestic use, are currently under way.

1.2 EPA SYNTHETIC FUELS ENVIRONMENTAL ASSESSMENT/CONTROL TECHNOLOGY DEVELOPMENT PROGRAM

Although coal conversion processes can produce clean-burning fuels, unless properly designed and operated, large scale facilities for the conversion of coal to gaseous or liquid fuels can by themselves constitute major sources of environmental pollution. In response to the increasing activities related to synthetic fuels, the Environmental Protection Agency has initiated a comprehensive assessment program to evaluate the environmental impacts of synthetic fuels from coal processes having a high potential for eventual commercial application. This overall assessment program is being directed by the Fuel Process Branch of EPA's Industrial Environmental Research Laboratory, Research Triangle Park (IERL-RTP). The primary objectives of the EPA synthetic fuels from coal program are to define the environmental effects of synthetic fuel technologies with respect to their multimedia discharge streams and their health and environmental impacts and to define control technology needs for an environmentally sound synthetic fuel industry. The synthetic fuel technologies being addressed in the EPA program include high Btu gasification, low/medium Btu gasification and coal liquefaction. To achieve the program's overall objectives, the EPA has defined six major tasks areas, each being supported through contract services. These six task areas are Environmental Assessment of High Btu Gasification, Environmental Assessment of Coal Liquefaction, Control Technology Development, Waste Stream Disposal and Utilization, and General Support. TRW is the EPA contractor for the Environmental Assessment of High Btu Gasification.

The specific objectives of the TRW program are (a) to characterize waste streams associated with the operation of commercial high Btu gasification facilities which use current and developmental technologies; (b) to identify control technologies required to reduce emissions to acceptable levels; and (c) to estimate environmental impacts. The study will provide input to the EPA effort for assessing the environmental impact, providing background for regulatory agencies and evaluating control technologies for the emerging coal gasification industry. The TRW effort consists of: (a) evaluation of existing process and environmental data and the data which are being generated by other EPA/DOE contractors and process developers working in related areas; (b) acquisition of supplementary data through sampling and analysis of process/

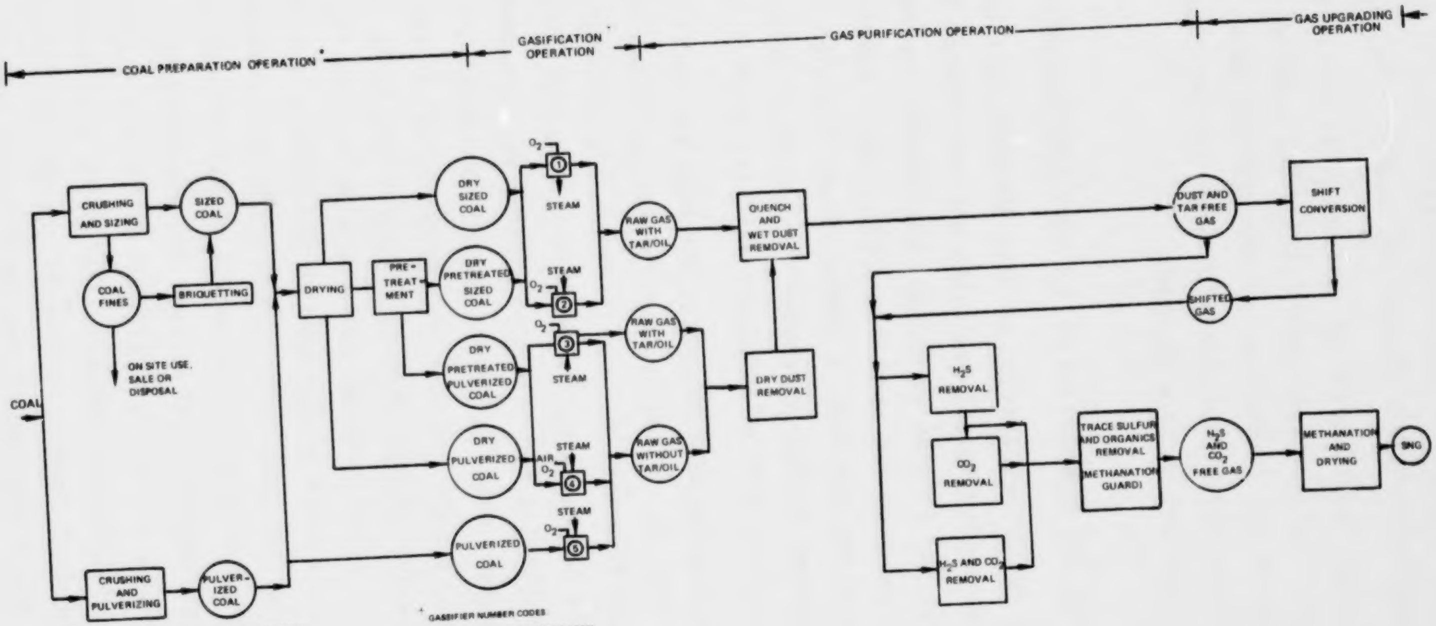
waste streams at selected gasification facilities; and (c) environmental assessment and necessary process engineering support studies.

As the first step toward detailed environmental assessment, TRW has reviewed the existing data on coal gasification and related operations and has identified gaps in and limitations of the existing data. The effort has included a preliminary impact assessment of high Btu gasification technologies. The findings are presented in this document.

1.3 METHODOLOGY FOR THE PREPARATION OF THE DATA BASE DOCUMENT

The data used in the preparation of this document have been obtained from several sources, including (a) published and unpublished EPA documents, (b) open literature, (c) process developers and EPA/DOE contractors, and (c) authorities in industry and academic institutions. Based on the preliminary review of the collected data, a number of gasification and related processes which were judged to have a greater likelihood of being employed in commercial SNG facilities were selected and analyzed in more detail.

To enable a systematic data analysis, the high Btu gasification technology was divided into the following four "operations" (see Figure 1-1): coal preparation, gasification, gas purification, and gas upgrading. In addition, for the purpose of analysis, the auxiliary processes which would be used in commercial SNG facilities for pollution control were grouped into air pollution control processes, water pollution control processes and solid waste management processes. Except for coal pretreatment, which would be necessary with certain gasification systems when caking coals are to be handled, the processes employed for preparation of coal for high Btu gasification are not unique to gasification and are widely used in the utility and other industries. Accordingly, except for the coal pretreatment which was reviewed in connection with gasification, the coal preparation operation was not addressed in this study. Since with some gasification systems the quenching and removal of dust from the raw product gas are accomplished within the gasifier or are integrated with the gasification operation, for discussion purposes, the review of the quench and dust removal portion of the gas purification operation was also included in the discussion of the gasification operation.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GAS PURIFICATION OPERATION
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5. ENTRAINED BED, SLAGGING

Figure 1-1 High Btu Gasification Operations and Process Modules

For analysis purposes, the operations and the auxiliary processes were subdivided into a number of process modules, with each module being comprised of a number of nearly interchangeable processes or processes applicable to different operating conditions and input requirements. For example, the auxiliary processes for air pollution control were grouped into sulfur recovery; tail gas treatment; SO_2 control and/or recovery; incineration; CO, hydrocarbon and odor control; particulate control; gas compression and recycling; and NO_x control. For each process in a module, a data sheet was prepared presenting key information items, thereby imparting high visibility to engineering "facts and figures," allowing ready comparison between alternate processes in a given module, and underlining specific areas where significant gaps existed in the available data. To assure the completeness and accuracy of the information, where applicable the data sheets on the processes reviewed were forwarded to the process developers/licensors and, in some cases, to technical experts in various EPA laboratories/program offices for review and comment. Lists of process developers/licensors to whom the data sheets were submitted for review and whether to date a response has been received or not are presented in Table 1-1. The comments received from the reviewers have been incorporated in this document.

The various processes in a module were compared from the standpoint of developmental status, suitability for use in SNG facilities, process principle, raw material and utility requirements, costs (where data are available), process efficiency and reliability, discharge stream characteristics, and other advantages and disadvantages. The gasification, gas purification, gas upgrading and pollution control processes which were judged to be promising were then examined from the standpoint of their integration into a commercial SNG production facility. The various options for gas treatment and upgrading and for pollution control in an integrated facility were then examined and gaps and limitations of the available data were summarized. In reviewing the process and pollution control unit operations and waste discharge characteristics in an integrated facility, only those unit operations and waste streams which were judged to be specific to high Btu gasification and related operations were addressed. Thus, individual operations such as coal storage, cleaning and drying; on-site power generation; oxygen production; and raw

TABLE 1-1. LIST OF PROCESS DEVELOPERS/LICENSORS TO WHOM DATA SHEETS WERE SENT FOR REVIEW AND THE STATUS OF RESPONSES RECEIVED

Process	Addressee	Date Sent	Response Received (as of 8/78)
Bigas	Lowell Miller DOE, Washington DC	11/22/77	*
Cogas	T. Eddinger Cogas Development Co. Princeton, N. J.	12/14/77	Yes
CO_2-Acceptor	E. L. Clark DOE, Washington DC	10/24/77	*
	John Sudbury Consolidated Coal Co. Library, Pa.	10/24/77	Yes
Hydrane	L. Jablansky DOE, Washington DC	11/16/77	*
Hygas	S. Verikios DOE, Washington DC	10/26/77	*
	Louis B. Anastasia Institute of Gas Tech. Chicago, Ill.	10/26/77	Yes
Koppers-Totzek	J. Anderson American Koppers Inc. Pittsburgh, Pa.	10/4/77	†
Lurgi (dry ash)	J. Pollaert American Lurgi Corp. Hasbrouck Heights, N.J.	10/18/77	‡
Synthane	E. L. Clark DOE, Washington DC	10/20/77	--
Texaco	W. Schlinger Texaco, Inc. New York, N.Y.	10/28/77	Yes[§]

(continued)

TABLE 1-1. CONTINUED

Process	Addressee	Date Sent	Response Received (as of 8/78)
Battelle	W. Corder Battelle Columbus, Ohio	1/16/78	Yes
Slagging Gasifier	R. Ellman Grand Forks Energy Research Center Grand Forks, S.D.	1/20/78	Yes
Rectisol	T. Pollaert American Lurgi Corp. Hasbrouck Heights, N.J.	11/11/77	‡
Purisol	T. Pollaert American Lurgi Corp. Hasbrouck Heights, N.J.	11/11/77	‡
Amisol	T. Pollaert American Lurgi Corp. Hasbrouck Heights, N.J.	11/11/77	‡
Selexol	J. P. Vallentine Allied Chemical Corp. Morristown, N.J.	10/26/77	Yes
Estasolvan	M. E. Mauss Institut Francais du Pétrole France	11/16/77	--
ADIP	H. J. McNamara Shell Oil Co. Houston, Texas	11/29/77	Yes
Sulfinol	H. J. McNamara Shell Oil Co. Houston, Texas	10/24/77	Yes
Fluor Econamine	R. Schaaf Fluor Engineers & Contractors Irvine, Ca.	12/8/77	Yes

(continued)

TABLE 1-1. CONTINUED

Process	Addressee	Date Sent	Response Received (as of 8/78)
Fluor Solvent	R. Schaaf Fluor Engineers & Contractors Irvine, Ca.	12/8/77	Yes
SNPA-DEA	E. J. Jirus Ralph M. Parsons Co. Pasadena, Ca.	1/24/78	Yes
MDEA	R. L. Pearce Dow Chemical Co. Freeport, Texas	1/24/78	Yes
Sulfiban	M. Peters Applied Technology Corp. Houston, Texas	1/24/78	Yes
Alkazid	L. Greives Davy Powergas Inc. Lakeland, Fla.	12/8/77	Yes
Benfield Hot Carbonate	D. McCrea Benfield Corp. Pittsburgh, Pa.	12/20/77	Yes
IFP	M. F. Mauss Institute Francais du Pétrole France	12/2/77	--
Sulfreen	Y. M. Philardeau Aquatine of Canada Ltd. Calgary, Canada	1/24/78	Yes
Claus	E. J. Jirus Ralph M. Parsons Co. Pasadena, Ca.	1/24/78	Yes
Cleanair	Art Holms J. F. Pritchard Co. Kansas City, Mo.	5/17/78	--
Stretford	A. Grant Woodhall-Duckham, Ltd. Pittsburgh, Pa.	11/28/77	Yes

(continued)

TABLE 1-1. CONTINUED

Process	Addressee	Data Sent	Response Received (as of 8/78)
Giammarco-Vetrocoke	Vetrocoke Cokapuania, SPA Milano, Italy	6/23/78	--
Beavon	W. J. Baral Union Oil Co. Brea, Ca.	12/21/77	--
SCOT	H. J. McNamara Shell Oil Co. Houston, Texas	11/29/77	Yes
Wellman-Lord	Davy Powergas Inc. Lakeland, Fla.	4/28/78	Yes
Chiyoda Thoroughbred 101	R. Dakan Chiyoda International Corp. Seattle, Wash.	2/17/78	Yes
Shell Copper Oxide	H. J. McNamara Shell Oil Co. Houston, Texas	11/29/77	--
Phosam W	R. Rice USS Engineers & Consultants Pittsburgh, Pa.	11/28/77	Yes
Chevron WWT	J. D. Knapp Chevron Research Corp. San Francisco, Ca.	11/30/77	Yes
Phenosolvan	T. Pollaert American Lurgi Corp. Hasbrouck Heights, N.J.	--	‡

*Although no formal review comments were received, DOE did supply a number of recent documents on the operation of the Hygas and Synthane pilot plants; the information in these documents has been incorporated in the data sheets for these processes.

†Koppers Co. will review the Kopper-Totzek data sheet as soon as an agreement is finalized.

‡Lurgi has indicated that it will not respond to TRW's request for the review of data sheets.

§Texaco indicated that it could not comment on the technical content of the data sheet without revealing information it considers confidential.

water and sanitary waste treatment were not considered. Some of these were addressed in Environmental Assessment Data Base for Low/Medium Btu Gasification Technology, EPA 600/7-77-125a and b, November 1977.

The information and the discussion presented in this report are based on the data available to TRW as of August 1978. TRW is aware of the plans by certain process developers to publish important updated information in the near future. Such information and other data which may become available in the future should be incorporated in any updated version of the present document.

1.4 ORGANIZATION OF REPORT

This data base document consists of three volumes: Volume I, Technical Discussion; and Volumes II and III, Appendices. The Appendices contain "data sheets" prepared on various processes reviewed and consist of: Appendix A, Gasification Operation; Appendix B, Gas Purification Operation; Appendix C, Gas Upgrading Operation; Appendix D, Air Pollution Control; Appendix E, Water Pollution Control; and Appendix F, Solid Waste Management. The technical discussion in Volume I represents a summary and analysis of the information presented in the data sheets including an examination of the pollution control options in commercial SNG facilities. Additionally, the major gaps and limitations of the available data are identified and the more relevant programs which could supply some of the needed data are highlighted. In the discussion in Volume I, a separate chapter has been devoted to each of the major operations (i.e., Gasification, Gas Purification, and Gas Upgrading) and auxiliary processes (i.e., Air Pollution Control, Water Pollution Control, and Solid Waste Management). The sources of data used in the preparation of the data sheets contained in the Appendices have been identified separately in each individual data sheet. Since much of the discussion in Volume I is based on the information in the data sheets, the reference sources for the information in the data sheets have not been repeated in Volume I.

2.0 GASIFICATION OPERATION

Based on preliminary analysis of various commercial and developmental gasification processes for use in SNG production, eleven processes were selected for detailed analysis. These processes, which utilize five types of gasifier designs, are listed in Table 2-1. Figure 2-1 is a schematic presentation of the gasification operation. Three of the processes listed in the table (Koppers-Totzek, Texaco, and Self-Agglomerating Ash) may not be likely candidates for SNG production (see Section 2.1) but were reviewed in this program at the request of the EPA.

The data sheets prepared for the eleven gasification processes are contained in Appendix A. This chapter summarizes the information contained in the data sheets. The general principles of high Btu gas production are reviewed and the key features of the promising gasification processes are presented. In addition, the status of various developmental and commercial high Btu gasification projects is summarized. Data relating to the properties of major discharge/waste streams from gasification and related operations are presented and analyzed from the standpoint of emission/effluent potential and impact on downstream processes or treatment systems. Finally, the data gaps and limitations are identified, along with ongoing or planned programs which should supply some of the needed data.

2.1 GENERAL PRINCIPLES OF AND APPROACHES TO HIGH BTU GASIFICATION

The conversion of coal to gaseous products generally involves four types of chemical reactions:

- Devolatilization/Pyrolysis

$$\text{Coal} \xrightarrow{\text{heat}} CH_4 + H_2O + C_xH_y \qquad (1)$$

TABLE 2-1. GASIFICATION PROCESSES EVALUATED

Lurgi (dry ash)	Fixed bed (dry ash)
Lurgi Slagging Gasifier	Fixed bed (slagging)
Hygas (steam-oxygen)	Fluidized bed (internal char gasification)
Cogas	Fluidized bed (external char gasification)
CO_2-Acceptor	" " "
Hydrane (Hydrogasification)	" " "
Synthane	" " "
Self-Agglomerating Ash	" " "
Bigas	Entrained bed (slagging)
Koppers-Totzek	" " "
Texaco	" " "

- Gasification

$$C + H_2O \xrightarrow{\text{heat}} CO + H_2 \qquad (2)$$

$$C + 2H_2 \longrightarrow CH_4 + \text{heat} \qquad (3)$$

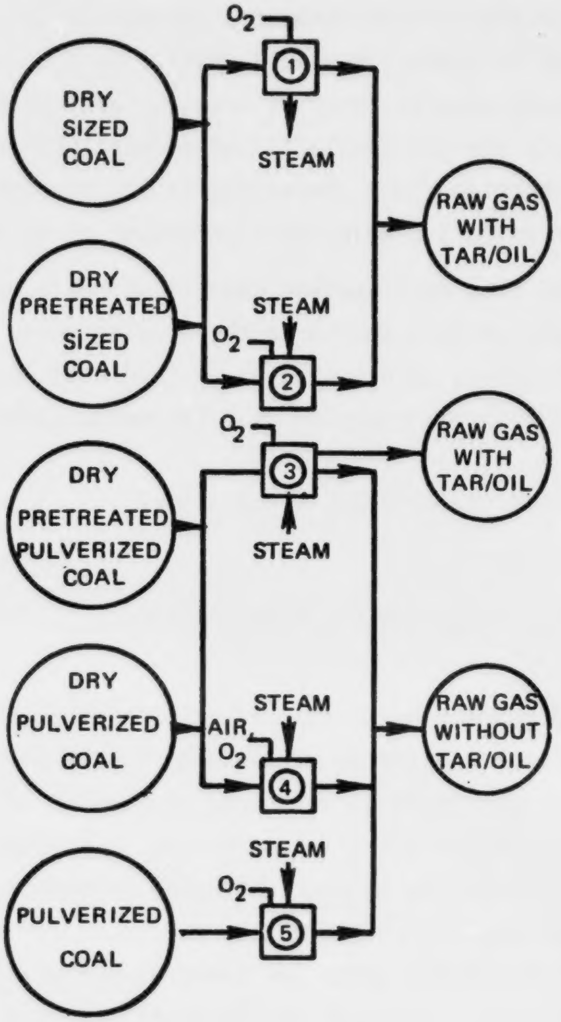
- Combustion

$$C + 1/2\ O_2 \longrightarrow CO + \text{heat} \qquad (4)$$

$$C + O_2 \longrightarrow CO_2 + \text{heat} \qquad (5)$$

- Water-Gas Shift

$$CO + H_2O \longrightarrow CO_2 + H_2 + \text{heat} \qquad (6)$$


DRY SIZED COAL
DRY PRETREATED SIZED COAL
DRY PRETREATED PULVERIZED COAL
DRY PULVERIZED COAL
PULVERIZED COAL
O_2
STEAM
AIR, O_2
①
②
③
④
⑤
RAW GAS WITH TAR/OIL
RAW GAS WITH TAR/OIL
RAW GAS WITHOUT TAR/OIL

GASSIFIER NUMBER CODES:

1. FIXED BED (DRY ASH)
2. FIXED BED (SLAGGING)
3. FLUIDIZED BED, INTERNAL CHAR GASIFICATION
4. FLUIDIZED BED, EXTERNAL CHAR GASIFICATION
5. ENTRAINED BED, SLAGGING

Figure 2-1. Process Modules for Gasification Operation

In all gasification processes, heat must be supplied directly or indirectly to promote reactions 1 and 2. Commonly, such heat is supplied by injecting air or oxygen into the gasifier to combust a portion of the feed coal (or into a separate system to combust residual char). In the coal flow sequence of most processes, three general zones of progressively higher temperatures are encountered. These are the devolatilization/pyrolysis zone, the gasification zone and the combustion zone. Depending on the process design, these zones may be encountered in a single reaction vessel or in separate vessels.

Production of SNG from coal-derived gases requires a methanation step to increase the methane content and hence the heating value of the gas (in most gasification processes, only a portion of feed coal is directly converted to methane in the gasifier via reaction 3). The methanation reactions are:

$$3H_2 + CO \longrightarrow CH_4 + H_2O + \text{heat} \qquad (7)$$

$$4H_2 + CO_2 \longrightarrow CH_4 + 2H_2O + \text{heat} \qquad (8)$$

To convert all the CO to methane in the methanation step, the molar ratio of hydrogen to carbon monoxide prior to methanation should be greater than 3. The conditions in many gasifiers do not favor production of enough hydrogen to achieve the required H_2/CO ratio. Accordingly, a supplementary catalytic shift conversion step (reaction 6) should precede methanation. In order to minimize shift and methanation requirements, processes for the production of high Btu gas feature conditions which are aimed at maximizing the formation of both methane and hydrogen directly in the gasifier. A common approach is to keep initial temperatures and residence times as low as possible in the devolatilization/pyrolysis zone. The direct reaction of carbon with hydrogen to form methane (reaction 3) is favored at relatively low temperatures (and high pressures) as is the shift reaction (reaction 6) to produce hydrogen. Thus, most processes are operated at high pressure and low to moderate temperature to maximize methane and hydrogen formation in the gasification zone. To generate the hydrogen required for reaction 3, sufficient quantities of steam and oxygen are added in the combustion zone to promote reactions 2 and 6.

Many gasification processes, especially those which employ fluidized beds, cannot directly handle a caking coal unless the coal is pretreated to destroy its caking tendencies. Particles of caking coals tend to agglomerate, thus preventing proper fluidization or, in the case of fixed bed processes, interfering with normal gas flow through the gasifier. The most common pretreatment method for destruction of the caking properties involve heating, (at temperatures up to $700^{\circ}K$ or $800^{\circ}F$, depending on the coal) in the presence of small amounts of oxygen and steam. In some gasification processes (e.g., Hygas), coal pretreatment is carried out in a separate vessel ahead of the gasifier. In other processes (e.g., Cogas), pretreatment is accomplished directly in the gasifier/pyrolyzers. In these processes, the pretreatment operation is an integral part of the gasification.

All high Btu gasification processes require (1) a bulk particulate removal step(s) to remove ash, char and oil/tar particulates, and (2) a quench step to cool raw product gas, remove moisture and condensible organics, and to achieve additional particulate removal. The bulk particulate removal is commonly accomplished using cyclones. In certain processes such as CO_2-Acceptor and Synthane, the cyclone is located inside the gasifier. In the case of Hygas and Bigas the cyclone is located outside the gasifier, but it is an integral part of the gasifier design. Spray systems using water or oil (e.g., in the Synthane process) are used for gas quenching. In the case of processes such as Hygas which use an oil slurry system for coal feeding, the oil is recovered in the quenching operation. For these processes the quench operation is process-specific and is considered an integral part of the gasifier design.

2.2 KEY FEATURES OF HIGH BTU GASIFICATION PROCESSES

As was indicated above, of the eleven gasification processes reviewed in this program, eight are considered candidates for use in SNG production. These eight processes are Lurgi (dry ash), Lurgi (slagging gasifier), Hygas (steam-oxygen), Cogas, CO_2-Acceptor, Synthane, Bigas and Hydrane. Table 2-2 summarizes the key features of these processes, based on the detailed information contained in the data sheets in Appendix A. The eight processes

TABLE 2-2. KEY FEATURES OF HIGH BTU GASIFICATION PROCESSES

Process	Development Status	Coal Feed and Pretreatment	Coal Feeding Method	Gasifier Design	Gasifier Temperature $^{\circ}$K($^{\circ}$F)	Gasifier Pressure MPa(psia)
Lurgi (dry ash)	Commercial for fuel and synthesis gas production	Limited to non-caking coals. Fine coal sizes must be briquetted	Pressurized lock-hopper	Fixed bed, counter-current gas/solids flow, temperature increases downward to effect pyrolysis and gasification	Max. bed temp. 1255-1644 (1800-2500)	2.1 - 3.2 (300-465)
Lurgi (Slagging Gasifier)	Pilot scale, demonstration plant under design	Limited to non-caking coals. Fine coal sizes may be utilized by injection into center of gasifier bed	Pressurized lock-hopper	Same as dry ash Lurgi	Max. bed temp. 1255-1644 (1800-2500)	0.7 - 3 (95 - 415)
Hygas (steam-oxygen)	Pilot scale; demonstration plant under design	Can use all domestic coals. Caking coals are pretreated with air and steam in fluidized bed at 315-400°K	Coal is slurried with light aromatic oil and charged to gasifier by high pressure slurry pump	Two stage, fluidized bed hydrogasification. Fluidized steam-oxygen gasification stage provides heat and gas for hydrogasification	Hydrogasification 750-1000 (900-1350) Steam-oxygen gasification: 1100 (1600)	6.2 - 7.1 (911-1040)
Cogas	Pilot scale; demonstration plant under design	Can use all domestic coals. Pretreatment for caking coals is accomplished in first stage pyrolyzer	Pneumatic feeding with recycle product gas	Coal is pyrolyzed in four fluidized stages with progressively higher temperatures. Char produced from pyrolysis of coal is sent to gasifier. Crude gas is produced from the reaction of char and steam, obtaining heat indirectly from the combustion of char with air. Gasifier gas flow counter-current to coal and char	Pyrolyzers 500-1000 (450-1500) Gasifier: 1200 (1700)	0.13 (20) 0.20 (29)
CO_2-Acceptor	Pilot scale; no demonstration or commercial project planned	Limited to more reactive coals (e.g., lignite and sub-bituminous coal)	Pressurized lock-hopper	In the gasifier, calcined dolomite supplies heat for steam gasification of coal. Carbonated dolomite is recalcined in a regenerator by burning char with air. Both vessels fluidized	Gasifier: 1090 (1500) Regenerator: 1280 (1860)	1.0 (150) 1.0 (150)
Synthane	Pilot scale	Can use all domestic coals. Caking coals are pretreated with O_2 and steam within the gasifier in a free fall fluidized bed zone	Pressurized lock-hopper	Steam and oxygen used to gasify coal in fluidized bed gasifier	960-1090 (1280-1500)	4.2 - 6.8 (600-1000)
Bigas	Pilot scale	Can use all domestic coals. No pretreatment is required	Coal is slurried with water and injected into pressurized drier before entering gasifier	Coal is gasified in an entrained bed with a steam/synthesis gas mixture. Char is gasified in an entrained bed using O_2 and steam to generate synthesis gas	Upper stage: 1200 (170) Lower stage: 1755 (2700)	8 (1175)
Hydrane	Bench scale	Caking coal permitted without pretreatment.	Injection nozzle	Direct hydrogasification of coal with hydrogen in a fluidized bed. Hydrogen would be produced by char gasification with subsequent purification	-6000 (~1500)	7.0 (1015)

(continued)

TABLE 2-2. CONTINUED

Process	Quench and Dust Removal	Ash/Char Removal	Typical Product Gas Composition* (vol %)				Tar/Oil Production	Gas Yield* Nm^3/kg (scf/lb) of Dry Feed Coal
			CH_4	H_2	CO	CO_2		
Lurgi (dry ash)	Water spray cooler to condense tars/oils and remove bulk particulates	Lockhopper water quench, water slurry transport	8-11	40	15-20	28-31	Yes	0.9-1.7 (16-30)
Lurgi (Slagging Gasifier)	Same as dry ash Lurgi	Lockhopper, followed by water quench of slag	5-8	28-30	57-61	3-7	Yes	2.0-2.1 (34-36)
Hygas (steam-oxygen)	Cyclone followed by water quench for oil and particulate removal	Water quench at gasifier pressure, water slurry transport	13-28	26-37	8-10	28-35	Yes	1.0-1.2 (17-20)
Cogas	Cyclone followed by venturi scrubber for removal of char fines and for recovery of oil	Slag quenched, transport not known	8-15	5-40	4-19	22-29	Yes	Gas: 0.12-.60 (2-12) Oil: 0.04--0.2 l/kg (0.005-0.025 gal/lb) coal
CO_2-Acceptor	Internal gasifier cyclone, external water spray tower for particulate removal	Coal ash leaves regenerator with flue gas and is collected by cyclone and scrubbing systems	14	56-59	15	9-11	No	1.35 (23)
Synthane	Internal gasifier cyclone, venturi scrubber	Lockhopper, water quench, steam transport	7-13	23-35	3-12	37-64[‡]	Yes[§]	1.2-1.5 (20-25)
Bigas	Cyclone, water spray tower for particulate removal	Slag quenched followed by lockhopper	5-8	32-38	15-19	21-23	No	2.0-4.0 (32-68)[†]
Hydrane	No information	No information, char utilization has not been determined	57-79	21-28	1-6	1	?	0.6-1.0 (10-17)

*Based upon data for actual operation for the most advanced stage of development

[†] N_2 free basis

[‡] Includes CO_2 used to pressurize the lockhopper

[§] With "free-fall" mode of coal injection; recent pilot plant runs involving "deep-bed" injection of coals have indicated little tar production use fixed beds (Lurgi and slagging gasifier), fluidized beds (Hygas, Cogas, CO_2-Acceptor, Hydrane, Synthane and Self-Agglomerating Ash) and entrained beds (Bigas). With the exception of Lurgi (dry ash), which is commercially available, the processes listed in Table 2-2 are in various stages of bench-scale and pilot plant development. With the exception of Bigas and Hydrane, all processes require some degree of pretreatment when handling caking coals. The coal feeding methods include use of lockhoppers (Lurgi and Synthane), oil slurry (Hygas), water slurry (Bigas) and pneumatic (Cogas). Operating temperatures in the gasifiers range from $500^{o}K$ to $1640^{o}K$ ($450^{o}F$ to $2500^{o}F$) and the operating pressures from slightly above atmospheric for Cogas to over 7 MPa (1000 psia) for Synthane and Bigas. Except for Cogas, Hydrane, and CO_2-Acceptor, the processes use lockhopper or slurry pressure letdown systems for ash/char discharge.

A slurry transport system is usually used for the transport of ash/char from the gasifier. Except for Lurgi (dry ash and slagging), cyclones are employed for the removal of the bulk of the particulates from raw product gas and (in the case of Cogas and CO_2-Acceptor) from flue gas from combustion of char. Water spray systems are employed for product gas cooling and condensation of tar/oil and moisture in all processes. Quenching of the product gas with an oil spray before the water quench has been suggested for the commercial design of some processes (e.g., Hygas).

As indicated in Table 2-2, there is a wide variation in the composition of the product gas from different processes. In general, higher temperature processes such as slagging gasification and Bigas tend to produce product gases with lower methane and CO_2 percentages and lower hydrogen/carbon monoxide ratios than low temperature processes such as CO_2-Acceptor, Hygas, Cogas, and Hydrane. Processes such as CO_2-Acceptor, Cogas and Hydrane which incorporate external char gasification tend to produce product gas with a lower CO_2 content than other processes which employ internal char gasification. The reported gas yields vary from 0.1 to 0.7 Nm^3/kg (2 to 12 scf/lb) of coal for Cogas to 2 to 4 Nm^3/kg (32 to 68 scf/lb) of coal for the Bigas. The ranges of gas yields for different processes and for a given process reflect differences in (1) feed coals, (2) degree of carbon conversion, (3) product gas compositions and (4) production of tars/oil in addition to gas.

In principle, product gases from essentially any gasification process can be converted to high Btu gas by shifting and methanation. The overall thermal and economic efficiency of such conversion is generally low when product gases contain essentially no methane and have low hydrogen to carbon monoxide ratios. Examples of processes whose product gas is unsuitable for economical conversion to SNG are Koppers-Totzek, Self-Agglomerating Ash, and Texaco. The product gases from these processes contain no methane and require extensive shift conversion and methanation for SNG production. Since only a portion of the heat generated during methanation and shifting can be usefully recovered, shifting and methanation represent a thermal penalty in addition to imposing higher capital and operating costs for these gasification processes. Furthermore, the product gas from these processes is at high temperatures, presenting a potentially high thermal loss. In the case of Koppers-Totzek and Self-Agglomerating Ash, the product gas is also produced at a low pressure, thus requiring an energy input for compression during processing and for pipelining. Finally, since shifting results in the production of CO_2, the greater the requirement for shifting is, the greater is the requirement for subsequent CO_2 removal and hence the higher the cost associated with acid gas treatment.

Table 2-3 is a summary of the major advantages and limitations of the eight high Btu gasification processes reviewed. As indicated in the table, the processes vary in their status of development (see Section 2.3); ability to use different coal types and sizes; methane, hydrogen and higher organics production; utility requirements; throughput rates and turndown ability; carbon conversion efficiency; and CO_2 removal requirements. Generally, a comparison of processes reveals inherent tradeoffs which must be made in order to take advantage of certain process features. For example, low pressure operation of the Cogas process simplifies vessel design and construction in exchange for higher compression costs (when compared to high pressure processes such as Hygas). Similarly, with the slagging Lurgi gasification process, lower steam consumption and higher throughput rates are realized at the expense of lower methane and hydrogen content of the product gas (when compared to the dry ash Lurgi).

TABLE 2-3. ADVANTAGES AND DISADVANTAGES OF HIGH BTU GASIFICATION PROCESSES

Process	Commercially Developed	Developed Through Pilot Plant Scale	Can Use All Coals	Requires Pretreatment of Caking Coals	Can Utilize All Size Fractions	Produces Condensible Organics (tars/oils)	High Throughput Rate	Methane Formation in Gasifier	Ratio of Hydrogen to Carbon Monoxide in Product Gas	Steam/Electricity Consumption	Operating Pressure	Complete Char Utilization	Turndown Ability	CO_2 Removal Required	Oxygen Plant Needed	Comments
Lurgi (dry ash)	Yes	Yes	No	Yes	No	Yes	No	Moderate	Moderate	Moderate	Moderate	Yes	High	Yes	Yes	Commercial operations not for high Btu gas production at present. Basis for several proposed commercial SNG projects
Lurgi (Slagging Gasifier)	No	Yes	No	Yes	No	Yes	Yes	Low	Low	Low	Moderate	Yes	High	Yes	Yes	Extensive tests at a modified dry ash Lurgi plant. Basis for a DOE-sponsored demonstration plant.
Hygas (steam-oxygen)	No	Yes	Yes	Yes	Yes	Yes	No	High	High	Moderate	High	Yes	Low	Yes	Yes	Pilot plant has demonstrated operations with several coals. High carbon utilization has not been attained to date. Basis for DOE-sponsored demonstration program.
Cogas	No	Yes	Yes	No	Yes	Yes	No	Moderate	High	Moderate	Low	Yes	Low	Yes	No	Integrated pyrolysis and gasification/combustion operations not demonstrated. Basis for DOE-sponsored demonstration program.
CO_2-Acceptor	No	Yes	No	Yes	Yes	No	No	High	Very High	Low	Moderate	Yes	Low	No	No	Successful demonstration at pilot plant stage. High cost of acceptor is a major obstacle to further demonstration of process.
Synthane	No	No	Yes	Yes	Yes	Yes*	No	High	High	High	High	No	Low	Yes	Yes	High pressure lockhopper feeding not demonstrated. Pilot plant has limited steady state operating time.
Bigas	No	No	Yes	No	Yes	No	Yes	Low	Moderate	Moderate	High	Yes	Moderate	Yes	Yes	Ability to control slag flow at a pilot plant has not been demonstrated.
Hydrane	No	No	Yes	Yes	Yes	Yes	Yes	Very High	Very High	High	High	No	Low	Yes	?	Small scale test only. Char utilization and hydrogen production not tested.

*With "free-fall" mode of coal injection; recent pilot plant runs involving "deep-bed" injection of coal have indicated little tar production.

2.3 STATUS OF HIGH BTU GASIFICATION TECHNOLOGY

Processes for gasifying coal in a manner suitable for subsequent conversion to SNG are in varying stages of development. The only commercially available process which has been proposed for SNG application is the Lurgi (dry ash) process. At least three processes (Slagging Lurgi, Cogas, and Hygas) are apparently sufficiently well along in their development to serve as the basis for DOE-sponsored demonstration plants. The CO_2-Acceptor process has been demonstrated at the pilot plant stage, although no immediate plans are known for further scale up. The Synthane process has been operated at pilot plant stage and steady-state operation has been achieved with non-caking coals. The Bigas process is at the pilot plant stage but has not yet attained representative steady state operation. A number of other processes (most importantly, Hydrane, Garrett and Exxon processes) have been evaluated at the Bench or laboratory scale.

Even though there are currently a number of proposed projects for the commercial production of SNG (see Section 2.3.1 below), no actual construction has been initiated on any of these facilities. The actual construction has been delayed by a number of factors, the most important of which is the inability to secure adequate private or public financing. The estimates of capital investment for a 7 MM Nm^3/day (250 MMSCFD) SNG facility using the Lurgi (dry ash) gasification process vary from $800 million to $1,400 million, with annual operating costs ranging from $120 million to $150 million.(1,2) These estimates indicate a product gas costing at least $2.70 per 10^6 Btu (based on utility financing method) and $3.70 per 10^6 Btu (based on private financing method). With most intra- and interstate natural gas currently selling for $2 per 10^6 Btu or less, SNG would not be cost competitive with natural gas (at least at the current regulated prices) and hence construction of commercial SNG facilities could not be economically justified. Although some cost reductions may eventually be realized with the development and use of "second generation" gasification processes, the comparative economics to date do not indicate that overall SNG costs associated with commercial use of such processes will be significantly lower (if at all) than those for Lurgi based plants. The development of a commercial SNG industry has also been impeded by the lack of agreement on the best energy policy for the U.S.

It has been argued, for example, that an energy resource allocation policy which would restrict or forbid the use of natural gas for such industrial activities as ammonia production and power and steam generation (which can use coal directly) can postpone, if not eliminate, the necessity for commercial SNG production. Furthermore, for these applications which can use coal directly, the direct use of coal represents a more efficient use of this resource when compared to conversion of coal to SNG and use of SNG for these applications.

Table 2-4 lists the existing and proposed commercial projects, planned demonstration programs, pilot projects and bench/laboratory projects utilizing high Btu gasification processes. A brief description of the projects listed in Table 2-4 follows.

2.3.1 Existing and Proposed Commercial Projects

At the present time, there are no commercial-scale facilities producing substitute natural gas in the U.S. or abroad. There are, however, 18 major commercial-scale facilities located abroad which use dry ash Lurgi process for production of low/medium Btu gas for a variety of applications, including hydrocarbon and ammonia synthesis. The Lurgi facilities include the 725 tpd (800 ton/day) SASOL plant in South Africa, the 0.84 MM Nm^3/D (30 MMSCFD) Westfield plant in Westfield, Scotland, and the 1.3 MM Nm^3/D (47 MMSCFD) facility in Kosovo, Yugoslavia(3). The existing SASOL facility (SASOL I) has been operational since 1958 and utilizes the gas produced from 13 Lurgi gasifiers for the production of hydrocarbons via Fischer-Tropsch synthesis. A second SASOL facility (SASOL II) is currently being constructed, which will expand the present plant capacity(4). The Westfield plant was constructed in 1958-59 for the production of medium Btu gas; in 1963 a water gas shift section was added to the facility, and in 1973 a methanation unit was tested for a brief period by a consortium of U.S. companies under the direction of Conoco Coal Development Co.(5,6) The Kosovo Plant has been in operation since 1971, and uses Lurgi gasifiers to convert lignite from adjacent mines to fuel gas and ammonia.

TABLE 2-4. PROPOSED HIGH BTU GASIFICATION COMMERCIAL AND DEMONSTRATION PROJECTS, AND PILOT AND BENCH PDU PROGRAMS

Process	Sponsor/Developer	Designer/ Operator	Location	Capacity	Status
1. Proposed Commercial Projects					
Burnham Project	El Paso Natural Gas Co., Pacific Gas & Electric, and an unnamed third partner	El Paso Natural Gas Co.	Northwest New Mexico	2MM Nm^3/D (72 MMSCFD)	FERC application pending, plant site lease under negotiation
Dunn Center Project	Natural Gas Pipeline Co. of American (NGPCA)	NGPCA	Dunn County, No.Dakota	7MM Nm^3/D (250 MMSCFD)	Water permit application denied in June 1976; new application under development
WESCO Project	Texas Eastern Transmission and Pacific Lighting Corp. (TET-PLC)	TET-PLC	Northwest New Mexico	7MM Nm^3/D (250 MMSCFD)	Project pending per FERC certification, project financing and plant site lease
Mercer County Project	American Natural Resources Co. (ANG) and Peoples Gas Co. (PGC)	ANG, PGC	Mercer Co., No.Dakota	7MM Nm^3/D (250 MMSCFD)	Plans tentative due to lack of Federal approvals and loan guarantee to finance construction
2. Proposed Demonstration Projects					
Slagging Lurgi	DOE and CONOCO Coal Development Co.	Foster-Wheeler Energy Corp.	Noble County, Ohio	3450 tpd (3800 ton/day)	22-month contract for engineering and technical support awarded by DOE in mid-1977. Construction phase (30 mos) and operation phase (42 mos). Contracts to be awarded at later date
Cogas	DOE and Illinois Coal Gasification Group	Dravo Corp.	Perry County, Ill.	2000 tpd (2200 ton/day)	21-month contract for conceptual design awarded mid-1977 by DOE
Hygas	DOE-Institute of Gas Technology	Procon, Inc.	--	--	$7.5MM contract is for conceptual design of 7MM Nm3/D (250 MMSCFD) commercial facility plus a smaller single-train demonstration facility
3. Pilot Projects					
Hygas	DOE, Institute of Gas Technology and American Gas Association	Institute of Gas Technology	Chicago, Illinois	73 tpd (80 tons/day)	Operational since 1973. Will continue through 1978. Successfully tested non-caking Montana lignite and subbituminous and caking Illinois bituminous coals
Synthane	DOE (PERC)	Lummus Co.	Bruceton, Pa.	65 tpd (72 ton/day)	Operational since mid-1976. Operation to continue through Sept. 1978. Non-agglomerating coals successfully tested. Operations plagued by a number of mechanical problems
Self-Agglomerating Ash	DOE, Battelle Memorial Institute and American Gas Association	Battelle Memorial Institute	West Jefferson, Ohio	23 tpd (25 ton/day)	Recently constructed; limited testing conducted to date including independent operation of the burner and gasifier up to 130 hrs. Approximately two years additional testing needed for complete process evaluation
Slagging Gasifier	DOE (GFERC)	Stearns-Roger, Inc.	Grand Forks, No. Dakota	0.91 tpd (1.0 ton/day)	Was operated from 1958-65 under Bureau of Mines. DOE contract awarded to Stearns-Roger in Oct. 1977 involves modification and operation of the pilot plant using bituminous coals
	Conoco, BGC, etc.	BGC	Westfield, Scotland	--	The 3-year program has involved modification of a Lurgi gasifier and its operation under slagging conditions. Ohio No. 9 and Pittsburgh No. 8 coals have been tested
CO_2-Acceptor	DOE and CONOCO Coal Development Co.	CONOCO	Rapid City, So. Dakota	36 tpd (40 ton/day)	Constructed in 1972; 42 runs conducted to date on a variety of coals and two types of acceptors. Testing was completed in fall 1977, having demonstrated technical feasibility of the process
4. Bench/PDU-Scale Projects					
Hydrane	DOE (PERC) and Rocketdyne	Dravo Corp.; Rocketdyne	Bruceton, Pa.	9.1 tpd (10 ton/day) Hydrane PDU; 0.23 tpd (0.25 ton/hr) bench-scale hydrogasification reactor	Hydrane PDU recently built by Dravo for DOE; a bench-scale Rocketdyne hydrogasification reactor is also being tested for DOE and appears to be superior to the Hydrane unit. Rocketdyne contract to expire in 1978
Garrett Process	Occidental Research & Development Co.	Occidental Research & Development Co.	LaVerne, Ca.	3.2 tpd (3.6 ton/day)	Plant has operated with West Kentucky coals to produce 229x 10^6kcal/Nm^3 (700 Btu/scf) gas
Exxon Process	Exxon Co.	Exxon	--	0.45 tpd (0.5 ton/day)	Small-scale testing is continuing

There are currently several proposals for the construction of commercial-scale (7MM Nm^3/day or 250 MM scf/day) facilities for SNG production in the United States based on the dry ash Lurgi process. The furthest along in planning of these proposals are: (a) the Burnham, New Mexico project, sponsored by the El Paso Natural Gas Co.(7); (b) the Dunn Center project for Dunn County, North Dakota, sponsored by the Natural Gas Pipeline Co. of America(8); (c) the WESCO Project sponsored by Texas Eastern Transmission and Pacific Lighting Corporation to be located in northern New Mexico(9); and (d) the Mercer County, North Dakota Project sponsored by the American Natural Resources Co., the Peoples Gas Company, and the Natural Gas Pipeline Company of America(10). Although environmental impact statements or assessments have been completed for each of these proposed projects, legal, regulatory and funding matters are stalling initiation of construction. For example, the Federal Energy Regulatory Commission is currently withholding approval of the Burnham facility pending resolution of matters pertaining to the acquisition of satisfactory commitments for coal(1,11). The WESCO project is also pending FERC certification enactment of a federal loan guarantee program and plant site leasing from the Navajo Indians(1,12). A water permit application was denied in June 1976 for the Dunn Center facility, and hence a new water permit application is currently being developed. The Mercer County project is currently scheduled for initial construction in 1979; however, plans are still tentative due to need for federal approval of the recently devised "all events tariff" plan to finance plant construction(13,14).

Other proposed Lurgi-based commercial-scale gasification projects which are in early planning stages are(1,15): the Watkins, Colorado, project sponsored by Cameron Engineers, Inc.; the Douglas, Wyoming facility sponsored by the Panhandle Eastern Pipeline Co. and the Peabody Coal Co.; and the Cities Service Gas and Northern Natural Gas Companies' facility planned for northern Wyoming.

2.3.2 Proposed Demonstration Projects

There are currently no operating domestic high Btu coal gasification demonstration projects. Contracts, however, have recently been awarded by the U.S. Department of Energy for the conceptual design of 3 major high Btu gasification demonstration plants. These are the Conoco Coal Development Company's slagging Lurgi facility to be located in Noble County, Ohio(16); the Illinois Coal Gasification Group's Cogas facility to be built in Perry County, Illinois(16); and a HYGAS demonstration plant to be designed by Procon, Inc.(16) The Conoco design for the Noble County project incorporates four slagging Lurgi gasifiers producing 1.7 MM Nm^3/D (59 MMSCFD) of SNG from 3,450 tonnes/day (3,800 tons per day) of coal. The selection of the slagging Lurgi process was based on the favorable results obtained in tests with American coals at a Lurgi gasifier in Westfield, Scotland modified to operate in the slagging mode.

The Perry County facility is to integrate COED fluidized bed pyrolysis technology, as developed by DOE and the FMC Corporation, with the Cogas process of steam gasification of COED char. The Cogas char gasification step was recently piloted in England at the facilities of the British Coal Utilization Research Association, Ltd. under the sponsorship of a consortium of U.S. firms. The 2,000-tpd (2,200-ton/day) facility is to produce 0.50 MM Nm^3/D (18 MMSCFD) of SNG and 285,000 l/D (2,400 Bbls/day) of syncrude. Procon Inc. has initiated the conceptual design of a commercial-scale facility for the Hygas process developed by the Institute of Gas Technology in Chicago, Illinois. The current Procon design is for 7 MM Nm^3/D (250 MMSCFD) facility, and the conceptual design of a smaller single train demonstration facility is to follow.

2.3.3 Pilot Projects

Several high Btu gasification processes are presently at the pilot plant stage of development. These processes are Hygas, Synthane, Bigas, Self-Agglomerating Ash, CO_2-Acceptor, and the slagging Lurgi gasifier. The following is a brief history and status of each of these pilot plant programs.

- Hygas - A 73-tonne/day (80-ton/day) Hygas pilot plant has been operated in Chicago since 1973 by the Institute of Gas Technology (IGT) under joint sponsorship of DOE and the American Gas Association (AGA). The plant has successfully tested non-caking Montana lignite and subbituminous coals and caking Illinois bituminous coals, using the steam-oxygen process for hydrogen generation. The steam-iron process is also currently being tested in a pilot plant at IGT designed to produce 0.29 MM Nm^3/D (1.1 MMSCFD) of hydrogen; the plant was completed in July 1976, and start-up operations began in October 1976. A third process for hydrogen generation, the electrothermal gasification process, was also tested at the Hygas facility from 1972 to 1974, when the Hygas reactor was converted to accept hydrogen from steam-oxygen gasification. Tests conducted at the Hygas pilot plant to date have demonstrated the very high carbon conversion necessary for commercial operation. Pilot plant operations are to continue through 1978 with the testing of bituminous coals.

- Synthane - A 65 tonne/day (72 tpd) Synthane pilot plant has been operated by Lummus Company for the Pittsburgh Energy Research Center since mid-1976 in Bruceton, Pa. The plant includes gas purification (Benfield and Stretford), as well as methanation units. Operational testing with nonagglomerating coals began in early 1977; no agglomerating coals have been tested to date. The plant was operated in the "free-fall" mode of coal injection during July-December 1976. This mode of operation resulted in the production of significant quantities of tar, frequent plugging of the internal cyclone "dip-leg" and overloading of quench and gas purification systems. Since February 1977 which the plant has been operated in the "deep bed" mode of coal injection, significantly fewer operational problems have been experienced and a total of several hundred hours of steady state operation has been achieved. A Coal Pretreatment System has now been installed for testing caking coals.

- Bigas - The Bigas gasifier has been under development since 1965 by Bituminous Coal Research, Inc. Under DOE and AGA sponsorship, a 110-tonne/day (120-ton/day) integrated pilot plant was constructed and operated by Phillips Petroleum Co. beginning in late 1976 in Homer City, Pennsylvania, based on operating data obtained from a 45-kg/hr (100-lb/hr) PDU operation. (The original DOE/AGA contract with Phillips has expired, but has been extended through December 1978.) The plant incorporates a Selexol system for removal of H_2S and CO_2 from gas from the shift conversion unit. The pilot plant has had continuing difficulties with slag removal from the gasifier. Various unsuccessful attempts have been made to prevent slag solidification and plugging of the slag tap-hole, including the addition of limestone as a fluxing agent to reduce slag viscosity. Problems have also been encountered in the measurement of solids feed to the gasifier and measurement of temperature in Stage 1 of the gasifier. Steady state coal and char gasification have not yet been demonstrated at the pilot plant. Further pilot tests will include increasing the operating pressure to the optimum level (10 MPa or 1500 psia). The life of various metals and refractory materials in the gasifier and in the coal conveying system will also be tested in future runs.

- Self-Agglomerating Ash - A 23-tonne/day (25-ton/day) process development unit was very recently constructed at West Jefferson, Ohio under the sponsorship of DOE and AGA using the Battelle self-agglomerating ash burner gasification process. (The Battelle technique is an outgrowth of a Union Carbide process for gasifying low-sulfur Western coal, and is designed to produce medium-Btu synthesis gas to be used as feedstock to chemical plants.) To date, only limited testing has been conducted, including independent operation of the burner and gasifier for varying times up to 130 hours. Subsequent testing is to include operating the burner while continuously circulating the solids and feeding coal into the gasifier. It is expected that an additional 2 years are needed for complete process evaluation.

- Lurgi (Slagging Gasifier) - A small (0.4-m diameter) slagging gasifier is currently being tested by DOE at its Grand Forks Energy Research Center (GFERC) pilot plant in Grand Fords, North Dakota. The plant has a capacity of 0.907 tonne/hour (1.0 ton/hour) and has performed successfully with bituminous char, lignite and lignite char. Stearns-Roger, Inc. received a $1.5 million DOE contract in October 1977 for design, modification and operation of the pilot plant, to permit studies leading to the goal of extended continuous operating periods and operation on selected bituminous coals. Operational improvements will include the addition of a second coal lock to stabilize operation and the installation of a stirrer in the upper portion of the gasifier bed to permit operation on agglomerating coals.

  Under DOE sponsorship, CONOCO and British Gas Corporation (BGC) have conducted tests with American coals (Pittsburgh No. 8 and Ohio No. 9) at a Lurgi gasifier in Westfield, Scotland, modified to operate under slagging conditions. These tests, which have been aimed primarily at collecting engineering data for the design of a demonstration plant in the U.S., have included 48-hr duration runs with (a) Ohio No. 9 premixed with coke; (b) Pittsburgh No. 8 premixed with coke; and (c) Pittsburgh No. 8 alone. While the runs with Pittsburgh No. 8 have been very successful, limited success has been obtained with the Ohio No. 9. Except for one additional "exploratory" run which is planned for August-September 1978 with Pittsburgh No. 8, the DOE/CONOCO slagging gasification test program at Westfield is considered complete.

- CO_2-Acceptor - Testing at the 36-tonne/day (40-ton/day) pilot plant constructed in Rapid City, South Dakota in 1972 for the Consolidated Coal Company's (CONSOL, now CONOCO) CO_2-Acceptor process was completed in September 1977. Since 1972, over 42 runs have been conducted using a variety of coal types, including North Dakota lignites, Texas lignite, and Montana and Wyoming subbituminous coals. Two types of acceptors (Ohio dolomite and South Dakota limestone) were also tested, and methanation of the product gas was also successfully demonstrated in 1975. CONOCO has prepared conceptual designs for a demonstration or commercial plant based on the

the CO_2-Acceptor process, although no commercial facility is currently planned. The pilot plant has been modified for testing of the Westinghouse Electric Corp. gasification process.

2.3.4 Bench/PDU Scale Projects

Among the current bench-scale projects are those aimed at the development of the Hydrane, the Garrett, and the Exxon processes. The Hydrane process has primarily been tested in a special two-stage bench-scale reactor at the Pittsburgh Energy Research Center in Bruceton, Pennsylvania. Based on this work, a 9.1-tonne/day (10-ton/day) PDU and a 27.2-tonne/day (30 ton/day) hydrogasification process using the Hydrane reactor design were recently prepared by Dravo Corporation for DOE. In March of 1977 DOE awarded the Rocketdyne Division of Rockwell International Corporation a contract to test a 0.23-tonne/hour (0.25 ton/hour) short residence time-high throughput hydrogasification reactor. This design currently appears to be superior to the Hydrane process design, which was judged by DOE in 1975 to be unfeasible for commercialization. Upon expiration of the Rocketdyne contract in FY 1978, the effort may be followed by the design, construction and testing of a 9- to 18-tonne/day (10- to 20-ton/day) process development unit.

The Garrett process is being tested in a 3.2-tonne/day (3.6-ton/day) plant in operation at the Occidental Research and Development Company laboratory in LaVerne, California.(17) The plant has successfully operated with West Kentucky coals to produce gas with a heating value of 5900 kcal/Nm^3 (700 Btu/scf).

The Exxon process, which utilizes fluidized-bed gasification at 846^{0}K-921^{0}K (1000^{0}F-1200^{0}F), has been tested at a 0.45-tonne/day (0.5-ton/day) unit.(1,4) Char which is withdrawn from the gasifier is partially burned with air in a char heater, then separated from the remaining flue gas and returned to the gasifier as a direct-contact, heat transfer medium. The construction of a 458-tonne/day (500-ton/day) gasifier has been deferred. Smaller scale research and engineering studies are continuing.

2.4 DISCHARGE STREAMS

All gasification processes generate a product gas stream and a char/ash stream. In addition, dust removal and quench systems will generate solids/slurries and quench waters or oils. Processes which have coal pretreatment steps will generate flue or off-gases. Lockhopper feeding systems may involve the discharge of pressurization gases. Finally, combustion flue gases will be generated by processes such as CO_2-Acceptor and Cogas which gasify/combust char externally to the main coal gasifier. In this section, data relating to the characteristics of the discharge streams from gasification operations are reviewed from the standpoint of potential pollutant emissions/hazards and impacts on downstream gas treatment and pollution control operations.

2.4.1 Product Gases

The major components of product gases from high Btu gasification processes are listed in Table 2-2 and were discussed in Section 2.2. In addition to methane, carbon oxides and hydrogen, raw product gases contain sulfur and nitrogen species, dust (tar, ash and partially gasified coal particulates) and in many cases condensible organics. (The data on dust and condensible organics removed by the quench and dust removal systems are presented in Section 2.4.2.) The sulfur- and nitrogen-containing compounds originate from the organic or pyritic sulfur and organic nitrogen in the feed coal. The amounts and nature of such compounds depend on the feed coal composition and the gasification conditions. Table 2-5 is a summary of the available quantitative data on the sulfur and nitrogen species present in raw gases from CO_2-Acceptor, Hygas, Lurgi (dry ash and slagging), Cogas and Synthane. (Similar data are not available for the Bigas and Hydrane.) Hydrogen sulfide is the major sulfur containing component and is found in concentration ranging from 400 to 32,000 ppmv. Other sulfur compounds (COS, CS_2, mercaptans and thiophenes) constitute from 1% to 15% of the total gaseous sulfur. Gaseous nitrogen compounds in product gases are primarily ammonia (200 to 13,000 ppmv) and hydrogen cyanide (less than 1 to 77 ppmv).

TABLE 2-5. TYPICAL SULFUR AND NITROGEN SPECIES COMPOSITION OF RAW PRODUCT GAS

Process	Feed Coal Type	Coal Sulfur, %	Gas Composition (ppmv)					
			H_2S	COS	CS_2	RSH	HCN	NH_3
CO_2-Acceptor	Lignite; N.D.	0.5 - 0.7	400-1300	15-40	-*	-	-	8000
HYGAS	Lignite; Montana	0.9	2300	-	-	-	-	5800-12800
	Subbituminous; Montana	0.9	-	-	-	-	-	1300-6630
	Bituminous; Ill.#6	2.8	7000	-	-	-	-	1300-6630
		4.3	14000-17000	-	-	-	-	-
Lurgi (dry ash)	Subbituminous; Montana	1.5	2170		315		2.4	5600
	Bituminous; Ill.#6	3.1	11,200		180		25	7760
	Bituminous; Ill.#5	3.6	10,600		232 †		77	6000
	Bituminous; Pittsburgh #8	2.6	7500		122		4.4	7200
	Bituminous; So. Africa	0.4	3000		-		-	-
Slagging Gasifier	Lignite; N.D.	-	-	-	-	-	-	2100
Cogas	Bituminous; Ill.	2.1	32,000	-	-	-	-	-
Synthane‡	Bituminous; Ill.	3.6	9800	150	10	110	-	-
	Subbituminous; Wyoming	0.5 - 0.9	1000-8000	32	-	10	<1-3	4700

* - indicates no data available

† Values in the brackets represent the sum total of COS, CS_2, RSH

‡ Data presented include both bench-scale and pilot plant data

2.4.2 Dusts, Tars and Oils, and Aqueous Condensates

Available data on the composition of cyclone dusts from various processes indicate that the dust usually contains large percentages of ungasified carbon, sulfur and nitrogen compounds. The quantity of dust entrained in the raw product gas depends upon the feed coal particle size and the type of the gasifier bed, and ranges from less than 0.1% by weight of the feed coal (e.g., in the case of Lurgi) to a few percent by weight of the feed coal (e.g., in the case of CO_2-Acceptor). The bulk of the dust and condensible organics are removed by the quench and dust removal systems. In commercial application of processes such as CO_2-Acceptor and Hygas, which generate large quantities of high carbon dust, the carbon value of the collected dust would be recovered by reinjection of dust into the gasifier or by separate gasification or combustion.

Tars and oils are produced in several gasification processes (see Section 2.2). Table 2-6 presents typical tar and oil production rates for six gasification processes. Bigas, CO_2-Acceptor and Synthane ("deep-bed" coal injection mode of operation) produce little or no tars and oils; no data are available on tars and/or oil production, if any, in the Hydrane process. As indicated in Table 2-6, from essentially zero to 16% by weight of coal (moisture and ash free basis) is converted to condensible organics, depending on the process. Such organics tend to be highly aromatic in character (e.g., Synthane tar contains about 50% 3-ring aromatic hydrocarbons and 20% heterocyclic aromatic compounds).

Aqueous condensates/scrubber waters contain suspended solids, organic substances (such as phenols), ammonia, sulfide, cyanide and thiocyanate. The "normalized" production rates for these "key" substances and of TOC (total organic carbon) and COD (chemical oxygen demand) are listed in Table 2-6 for six gasification processes. (No data are available for Bigas and Hydrane.) The quantity of ammonia found in the condensate varies from 4 to 15 kg/1000 kg of coal and accounts for most of the nitrogen present in the feed coal. The reported production ranges for sulfide and thiocyanate are 0.1 to 4 kg/1000 kg of coal and 0.06 to 5 kg/1000 kg of coal, respectively. For the processes listed, very little cyanide is found in the quench water, presumably due to the reaction of cyanide with sulfide in the presence of oxygen to produce thiocyanate.

TABLE 2-6. SUMMARY OF NORMALIZED CONSTITUENTS PRODUCTION FOR GASIFICATION PROCESS (KG/1000 KG MOISTURE AND ASH FREE COAL)

Process	Data Source	Coal Type	Condensable Organics		Sum Total of Components in Quench, Scrub and/or Condensate Waters							
			Tar	Oil	TOC	COD	Phenol	CN^-	SCN^-	NH_3	$S^=$	TSS
CO_2-Acceptor	Pilot Plant	Lignite; N.D.	None	None	2 ±0.1	1.5 ±0.4	0.025 ±0.01	0.014 ±0.003	0.06 ±0.07	12 ± 7	0.2 ±0.1	23 ± 13
Hygas	Pilot Plant	Lignite; Montana	None	~85	20 ± 7	--*	7 ± 1	<0.001	1.2 ±0.4	15 ± 8	0.1 ±0.5	61 ± 30
		Subbituminous; Montana	None	~125	5 ± 1.5	--	8 ± 2	<0.001	0.5 ±0.1	7 ± 2	0.3 ±0.1	187 ± 56
		Bituminous;Ill.#6	None	--*	14 ± 3	--	6 ± 2	<0.001	5 ± 1	9 ± 4	4 ± 1	75 ± 50
Lurgi (dry ash)	Commercial gasifier, tests with American coals	Subbituminous, Montana	30	30	--	28 ± 7	8 ± 2	~0.005	0.06 ±0.07	6 ± 3	0.2 ±0.1	--
		Bituminous;Ill.#6	30	5	--	26 ± 1	6 ± 1	~0.02	0.15 ±0.04	8 ± 1	0.2 ±0.1	--
		Bituminous;Ill.#5	40	7	--	22 ± 1	6 ± 1	~0.01	0.18 ±0.02	8 ± 2	0.2 ±0.1	--
		Bituminous; Pittsburgh #8	40	9	--	15 ± 1	4 ± 1	~0.01	0.26 ±0.06	8 ± 1	0.1 ±0.05	--
Slagging Gasifier	Pilot plant	Lignite; N.D.	{ 37}‡		8 ± 3	--	--	--	--	4 ±0.1	2 ±0.1	--
Cogas	Pilot plant	Bituminous;Ill.#6	{~160}				~20					60 - 90†
Synthane	Bench-scale	Bituminous;Ill.#6	{ 37}		--	8	1	None	0.1	8	0.2	15 **
	Pilot plant "free-fall"	Subbituminous, Montana	--§		--	3.5-17	0.2-2.4	--	--	0.06-2.3	0-0.2	7.5-60†
	"deep-bed"	Subbituminous, Montana	--§		--	0.05-6	<0.004	--	--	0.03-3.3	0-0.3	0-150†

*Data not available (see text)

†Does not include suspended solids associated with char/ash quenching

‡Values in the brackets represent the sum total of tars and oils

§Although no quantitative data are available, it has been shown that very little tars/oils are produced with the "deep-bed" injection mode of operation, whereas significant quantities of tars/oils are produced with the "free-fall" mode of operation.

**Does not include particulates collected prior to quenching.

As indicated in Table 2-6, the CO_2-Acceptor and the Synthane ("deep-bed" injection mode of operation), which produce essentially no tars and oils, show low levels of TOC, COD and phenol in the quench water. In contrast, processes such as Hygas, Lurgi (dry ash and slagging) which produce appreciable quantities of condensible organics show high levels of TOC (5 to 20 kg/kg of coal), COD (15 to 30 kg/kg of coal), and phenols (4 to 20 kg/kg of coal). Data from dry ash Lurgi and Synthane operations (not contained in the table) indicate that tars contain small amounts of As, Pb, Hg, and Cd and that condensate/quench waters contain F, Se, B, Hg, Sb, Cd, and As in measurable quantities.

2.4.3 Char/Ash

Limited data are available on the characteristics of residual chars or ashes produced in various high Btu gasification processes. Reported values for the residual carbon in char/ash varied from a few percent for the slagging Lurgi and Bigas processes to over 50% for Synthane. Chars and ashes also retain some of the original coal sulfur and nitrogen and contain the bulk of the original inorganic component of the feed coal.

The trace element composition of several chars/ashes has been determined and can be compared to the composition of feed coals for potential losses during gasification. Table 2-7 summarizes the available information regarding retention of feed coal trace elements by chars produced by four gasification processes. As indicated in the table, Hg, As, Sb, and F are generally volatilized to a large extent during gasification and would appear in the raw product gas; Cd, B, Se, and Be are only partially volatilized. Other elements tend to be retained by chars/ashes. The sampling and analytical uncertainties involved in trace element determinations to date have generally precluded accurate material balance closure around gasification operations.

2.4.4 Lockhopper Vent Gases

As discussed in Section 2.2, some high pressure gasification processes (e.g., Lurgi and Synthane) use lockhoppers for feeding coal to and removing ash from the gasifier. Essentially no operating data are available on the composition of lockhopper vent gases. In the case of feed coal vent gases,

TABLE 2-7. PRECENTAGES OF SELECTED FEED COAL TRACE ELEMENTS RETAINED WITH CHAR OR ASH IN GASIFICATION PROCESSES

Element	Lurgi (dry ash) Bituminous So. African	Lurgi (dry ash) Bituminous Illinois #6	Hygas Bituminous Illinois #6	Synthane Bituminous Illinois #6	CO_2-Acceptor* Lignite; N.D.
Be	1	80	--	50-90	R
Hg	40	1	13	16	L
Cd	40	--	40	100	R
Sb	40	10	--	--	L
Se	--	--	--	100	PL
Mo	--	10	--	--	--
Co	--	100	63	--	--
Ni	154	125	100	20-80	R
Pb	180.	80	100	100	R
As	36	1	--	60-100	PL
Cr	--	300	100	30-70	R
Cu	--	200	90	--	--
B	36	40	60	60-100	--
Zn	--	90	--	40-100	--
V	72	90	54	40-60	R
Mn	154	90	>100	20-65	--
F	54	<1	--	10-20	--

*Preliminary qualitative results based on limited information; R = retained, L = lost, PL = Partially lost the vent gas composition would depend primarily upon the gas used for pressurization. The vent gas is also expected to contain coal devolatilization products, particulate matter and components of the gas in the gasifier (e.g., H_2S, COS and NH_3). Two options that are available for feed lockhopper pressurization are: (1) use of raw or cleaned product gas and (2) use of carbon dioxide from acid gas treatment. In the former case, the heating value of vented gases can be recovered by recycling the gas (after compression) or by using the gas as plant fuel. When the latter option is used, the CO_2 vent gas can be discharged to the atmosphere (after pollution control). In either case, a small volume of gas (nearly equal to the volume of the coal charge) would have to be discharged to the atmosphere (after pollution control).

Ash lockhoppers are usually pressurized with steam. The vent gases from depressurization would be expected to contain particulate matter and some of the components of the gasifier gas. The ash lockhopper vent gas has no fuel value and would be discharged to the atmosphere (after treatment). The vent gas from both the ash and feed lockhoppers is likely to contain odorous substances such as mercaptans and H_2S. Treatment for odor control may be necessary before these vent gases are discharged to the atmosphere.

2.4.5 Flue or Off-Gases

Flue or off-gases can arise from coal pretreatment and from the external gasification/combustion of char (see Section 2.2). Limited data are available relating to the composition of pretreatment off-gases. Pretreatment operations at the Hygas pilot plant have indicated that about 25% of the original coal sulfur may be released during the process. Off-gases will also contain particulates, carbon monoxide and organics. The disposition of such gases depends upon the plant design. At the Hygas pilot plant, off-gases are scrubbed before atmospheric discharge. At the Synthane pilot plant, pretreatment is integral with gasification and hence the off-gas becomes a component of raw product gas. In a commercial facility, off-gases may be directly flared or fed to the utility boiler (for recovery of fuel value and/or for pollution control).

In the CO_2-Acceptor, Synthane and Cogas processes, the char generated in the gasifier would be combusted in a separate operation to recover heat value. The combustion of such chars would generate a flue gas containing particulate matter and carbon, sulfur, and nitrogen oxides. Only limited data are available for the combustion of the CO_2-Acceptor char; no data are available on the flue gas generated from the combustion of char from Synthane and Cogas processes.

2.5 DATA GAPS AND LIMITATIONS

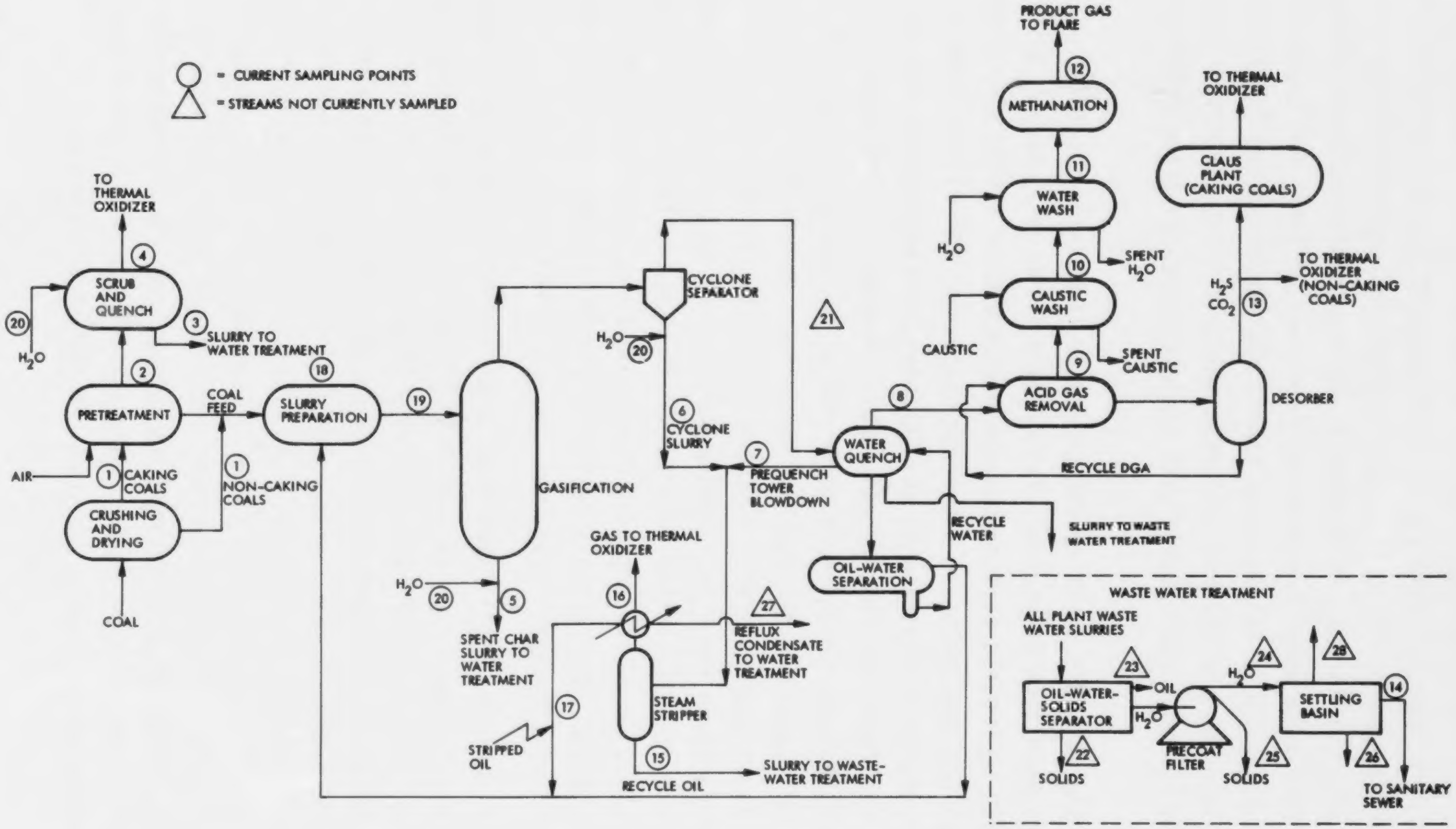
With the exception of the dry ash Lurgi, the high Btu gasification processes discussed in this chapter have only been tested in the pilot plant or bench scale units. Even though some process/waste stream data have been generated as the result of these developmental programs, in many cases such data are not comprehensive in that all streams are not addressed and all potential pollutants and toxicological and ecological properties are not identified. Even though much of the bench-scale/pilot plant data may have the limitations of not necessarily representing conditions encountered in large-scale facilities, the collection of environmental data during bench-scale/pilot plant testing is important since such data can provide the basis for comparison of processes and operational modes from the standpoint of pollutant generation, downstream pollution control requirements and overall environmental impacts.

The assessment of the environmental data collected in small-scale facilities should take into account the possible differences which may exist between experimental and commercial operations. For example, the quench systems for pilot plant facilities have not been generally designed for optimum performance and for minimizing water use and maximizing overall plant thermal efficiency. In most pilot plant facilities, relatively high grade water is used for raw product gas and ash quenching. In a commercial facility, "lower grade" process waters from elsewhere in the plant would be used for such purposes. Based on the experience gained in the pilot plant tests, the quench systems designed for full scale operation would most likely incorporate certain modifications to the smaller units.

Several of the high Btu gasification processes (e.g., Bigas and Hydrane) are in early developmental stages. To date, most of the operating effort at the bench-scale/pilot facilities has involved equipment shakedown and "debugging" and very limited or no steady-state operation has been achieved. The very limited data which are available for some of these processes (e.g., Synthane) do not reflect steady state conditions projected for large-scale operation. To date, the Synthane process, which is being developed to use caking coals, has only been tested with non-caking coals at the pilot plant level.

Two of the high Btu gasification processes (Cogas and slagging gasification) have been extensively tested by private developers. Detailed technical data on process performance and process/waste stream characteristics, however, have not been released for these processes. Of all the high Btu gasification processes reviewed in this chapter, the most extensive amount of data are available for the dry ash Lurgi. A major limitation of these data, however, relates to the fact that most of the operation has been with foreign coals. Under DOE sponsorship, tests have been carried out with four American coals at the Westfield, Scotland, Lurgi gasification facilities. The data generated in these tests which account for much of the available data suffer from the limitation that the coals used are generally not those which are to be used in the proposed commercial Lurgi facilities in the U.S. These data, however, do provide a basis for predicting process performance and stream characteristics associated with the use of different coals.

As noted earlier, the limited data which are available on the composition of the discharge streams from various high Btu gasification processes suffer from a general limitation of not being very comprehensive. In many cases, the characterization of a waste stream is in terms of gross parameters such as COD and TOC rather than specific constituents. Table 2-8 summarizes the available data for the Hygas pilot plant (Figure 2-2) and identifies additional analytical data which are needed for a comprehensive discharge stream characterization. The data needs identified in the table are those which can be obtained through the implementation of a sampling and analysis plan using the EPA's phased approach beginning with "Environmental Assessment Sampling and Analysis: Phased Approach and Techniques for Level 1"



○ = CURRENT SAMPLING POINTS
△ = STREAMS NOT CURRENTLY SAMPLED
TO THERMAL OXIDIZER
4
SCRUB AND QUENCH
20
H_2O
3
SLURRY TO WATER TREATMENT
2
PRETREATMENT
COAL FEED
AIR
1
CAKING COALS
1
NON-CAKING COALS
CRUSHING AND DRYING
COAL
18
SLURRY PREPARATION
19
GASIFICATION
H_2O
20
5
SPENT CHAR SLURRY TO WATER TREATMENT
CYCLONE SEPARATOR
H_2O
20
6
CYCLONE SLURRY
7
PREQUENCH TOWER BLOWDOWN
21
GAS TO THERMAL OXIDIZER
16
27
REFLUX CONDENSATE TO WATER TREATMENT
STEAM STRIPPER
17
STRIPPED OIL
15
SLURRY TO WASTE-WATER TREATMENT
RECYCLE OIL
8
WATER QUENCH
OIL-WATER SEPARATION
RECYCLE WATER
SLURRY TO WASTE WATER TREATMENT
PRODUCT GAS TO FLARE
12
METHANATION
11
WATER WASH
H_2O
10
SPENT H_2O
CAUSTIC WASH
CAUSTIC
9
SPENT CAUSTIC
ACID GAS REMOVAL
RECYCLE DGA
DESORBER
TO THERMAL OXIDIZER
CLAUS PLANT (CAKING COALS)
H_2S
CO_2
13
TO THERMAL OXIDIZER (NON-CAKING COALS)
WASTE WATER TREATMENT
ALL PLANT WASTE WATER SLURRIES
23
OIL
OIL-WATER-SOLIDS SEPARATOR
22
SOLIDS
H_2O
PRECOAT FILTER
24
H_2O
25
SOLIDS
28
SETTLING BASIN
14
26
TO SANITARY SEWER

Figure 2-2. Hygas Pilot Plant Sampling Point Diagram

TABLE 2-8. HYGAS PILOT PLANT STREAM CHARACTERIZATION DATA COLLECTED OR PLANNED TO BE COLLECTED BY IGT AND ADDITIONAL DATA NEEDED BY EPA FOR DISCHARGE STREAM CHARACTERIZATION

Streams			Published Data for Various Coals Tested				
No.*	Description	Lignite	Subbituminous	Medium Sulfur Bituminous	High Sulfur Bituminous	Additional Data Expected To Become Available As Part of Ongoing IGT/DOE Program†	Data Needed But Not Generated By Known Existing or Planned Sampling/Analysis Programs‡
1	Crushed/Dried Coal	Ultimate Analysis[1]	Ultimate Analysis, Trace Elements[2]	Ultimate Analysis	Utlimate Analysis	Ultimate Analysis, Trace Elements, Sulfur Species[3]	None[††,‡‡]
2	Pretreated Coal	N/A[§]	N/A	Ultimate Analysis	-[**]	Utlimate Analysis	None[††]
3	Pretreatment Quench Water	N/A	N/A	Major Constituents and Gross Parameters[4]	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters	Organic Compounds,[5] Trace Element Treatability[9], Radioactivity
4	Pretreatment Quench Off-Gas	N/A	N/A	-	Total Sulfur	Major Gas Components,[6] Total Sulfur	Trace Sulfur and Nitrogen Gases[7] Particulate[8], Organic Compounds, Radioactivity[12]
5	Spent Char Slurry	Ultimate Analysis, Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	Ultimate Analysis, Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Sulfur Species	Major Constituents and Gross Parameters, Sulfur Species, Trace Elements	Organic Compounds, Treatability, Radioactivity
6	Cyclone Slurry	Utlimate Analysis	Major Constituents and Gross Parameters, Trace Elements	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	Organic Compounds, Treatability, Radioactivity
7	Prequench Blowdown Gross Parameters	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	Organic Compounds, Treatability, Radioactivity
8	Quenched Product Gas	Major Gas Components	-	Major Gas Components	-	Major Gas Components, Trace Sulfur and Nitrogen Gases	Particulate, Organic Compounds, Radioactivity
9	Clean Product Gas	Major Gas Components, Trace Sulfur Gases	-	Major Gas Components, Trace Sulfur Gases	-	Major Gas Components Trace Sulfur Gases	None
10	Spent Caustic	-	-	-	-	-	None
11	Methanator Feed	Major Gas Components, Total Sulfur	-	Major Gas Components Total Sulfur	-	Major Gas Components, Total Sulfur	None
12	Methanator Gas	Major Gas Components, Total Sulfur	-	Major Gas Components, Total Sulfur	-	Major Gas Components, Total Sulfur	None
13	Acid Gas	Major Gas Components Trace Sulfur Gases	-	Major Gas Components, Trace Sulfur Gases	-	Major Gas Components Trace Sulfur Gases	None
14[§§]	Settling Basin Effluent	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	-	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	Organic Compounds, Treatability, Radioactivity
15	Stripper Bottoms	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	Ultimate Analysis, Major Constituents and Gross Parameters	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	Organic Compounds, Treatability, Radioactivity
16	Stripper Vent Gas	Major Gas Components	-	-	-	-	Major Gas Components, Organic Compounds
17	Stripped Oil	Ultimate Analysis, Organic Compounds	Organic Compounds	Ultimate Analysis	-	-	Organic Compounds

(continued)

TABLE 2-8. CONTINUED

Streams		Published Data for Various Coals Tested				Additional Data Expected To Become Available As Part of Ongoing IGT/DOE Program †	Data Needed But Not Generated By Known Existing or Planned Sampling/Analysis Programs‡
No.*	Description	Lignite	Subbitumious	Medium Sulfur Bituminous	High Sulfur Bituminous		
18	Slurry Preparation Vent Gas	-	-	-	-	-	Major Gas Components, Organic Compounds
19	Coal/Oil Slurry	Only Flow Rate	-	Flow Rate	-	-	None
20	Make-Up Water	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters	Major Constituents and Gross Parameters, Trace Elements	None
21	Raw Product Gas	-	Major Gas Constituents	Major Gas Constituents	-	Major Gas Constituents Trace Sulfur and Nitrogen Gases	Particulate, Organic Compounds
22	Separated Solids/ Sludge	-	-	-	-	-	Ultimate Analysis, Organic Compounds, Trace Elements, Treatability, Leochate Analysis,[11] Bioassay, Radioactivity
23	Separated Oil	-	-	-	-	-	Utlimate Analysis, Trace Elements, Organic Compounds, Bioassay[10]
24	Pond Influent	-	-	-	-	-	Major Constituents and Gross Parameters, Trace Elements, Organic Compounds, Treatability
25	Filter Solids	-	-	-	-	-	Ultimate Analysis, Organic Compounds, Trace Elements Treatability, Leochate Analysis,[11] Bioassay, Radioactivity
26§§	Pond Solids	-	-	-	-	-	Ultimate Analysis, Organic Compounds, Trace Elements, Treatability, Leachate Analysis,[11] Bioassay, Radioactivity
27	Reflux Condensate	-	-	-	-	-	Major Constituents and Gross Parameters, Organic Compounds
28	Fugitive Emissions	-	-	-	-	-	None

*See Pilot Plant Sampling Point Diagram (Fig. 2-2)

†These additional data pertain to tests with different coals and/or different operating conditions.

‡Provided that the information listed in the preceeding columns will be obtained by IGT/DOE as assumed.

§N/A = Not Applicable

**No data available to TRW on any sampling (previous or planned) of these streams

††None indicates that either the existing data and/or the data planned for acquisition are adequate or that the specific streams are not of interest because they are not scalable to commercial operations.

‡‡Selected time-specific sampling of coals may be necessary for interpretation of data on other streams and for material balance calcuations.

§§Pond receives wastes from the Hygas pilot plant as well as from other sources at the site; accordingly, streams Nos. 14 and 26 are not solely reflective of the Hygas pilot plant.

DESCRIPTION OF ANALYSES

1) Ultimate Analysis	C, H, N, S, Ash, volatile material, moisture
2) Trace Elements	Fe, Ba, Mn, Na, Zn, La, Cr, Cu, Cd, Pb, Hg, Mo, B, Be, F, Ti, V, Ca, Mg, Na, Al, K, Y.
7) Sulfur Species	Organic, Pyritic, Sulfate
4) **Major Constituents and Gross Parameters**	TD, TSS, TOC, pH, Phenol, CN^-, SCN^-, $S^=$, NH_3, Cl^-, Oil, Total S
5) Organic Compounds	Specific Compounds including environmentally important members of the following classes: olefins; aromatics; POM; N, S, and O Compounds, Etc.
6) Major Gas Constituents	CO_2, CO, H_2O, H_2, CH_4, C_2^+, N_2 (& Ar), H_2S
7) Trace Sulfur and Nitrogen Gases	NH_3, HCN, COS, CS_2, R-SH
8) Particulate	Total mass loading, size fractions, trace elements.
9) Treatability	Includes biodegradability, settleability, filterability, dewaterability, etc.
10) Bioassay	Ames type tests, acute/chronic toxicity, etc.
11) Leachate Analysis	Water leaching and leachate analysis for major and trace elements, gross parameters, and organic compounds.
12) Radioactivity	Gross α, β counts and U, Th concentrations.

(Rpt. No. EPA-600/2-77-115, June 1977) in combination with the ongoing DOE program.

2.6 RELATED PROGRAMS

A number of programs are currently being sponsored by the EPA and DOE which would generate some of the needed data identified above. Among the EPA-sponsored programs are those conducted by: (a) the Research Triangle Institute for experimental studies of pollutant production during gasification; (b) Illinois State Geological Survey for characterization of coal and coal residues; and (c) the Radian Corporation for environmental assessment of low/medium Btu gasification. Programs sponsored by DOE include: (a) the high Btu coal gasification pilot plant environmental assessment program coordinated by Carnegie-Mellon University; and (b) programs being conducted by the DOE national laboratories. Many of these programs are broad in scope and are expected to generate data pertaining to all operations in an integrated commercial plant and not only to the gasification operation reviewed in this chapter. A brief review of the EPA- and DOE-sponsored programs follows.

2.6.1 EPA-Sponsored Programs

- Research Triangle Institute (RTI)(18) - In November 1976 the Research Triangle Institute began a 5-year program to identify and semi-quantitatively determine the specific chemical species present in various effluents from gasification and other synfuels processes. The pollutants are to be ranked in order of their potential environmental hazard, based on such factors as concentration; amenability to treatment; disposition, dispersion, and dilution of the effluent stream; and ultimate pathways to human exposure. In addition, a tabulation of kinetic data pertaining to the rates of formation of environmentally significant pollutants will be generated.

  The RTI program includes the design, construction and operation of a laboratory-scale gasification reactor of sufficient flexibility to simulate the operating conditions of candidate commercial processes. To date, the gasifier has been operated with coke and Illinois No. 6 bituminous coal. In addition, a sampling train is under design for the acquisition of char, tar, oil, water and gas samples from the reactor. Multimedia analytical techniques are also currently being developed, calibrated, and tested for the determination of pollutants generated by the gasifier.

- Illinois State Geological Survey (ISGS)(18,19) - The ISGS is continuing a multi-year program which has 3 primary objectives: (a) to characterize the chemical, physical and mineral properties of coals, coal by-products and coal wastes; (b) to investigate the effects of pyrolysis on the distribution of trace elements between the volatile components and the residue; and (c) to provide data on the solubilities and toxicities of potential pollutants contained in solid coal wastes. To date, significant data have been generated on the chemical form of minor and trace elements in coal and coal char, and correlations are currently being developed for various elements to determine their association with coal minerals and organic matter. Recent pyrolysis studies have determined that certain elements are more volatile in lignites than in bituminous coals, based on data obtained on a continuously-fed coal char furnace constructed as part of the program. Toxicity and bioassay studies of leachates from solid coal wastes have been conducted. Other pyrolysis, leaching and toxicity studies are in progress.

- Radian Corporation(20,21) - As part of EPA's comprehensive Synthetic Fuels Environmental Assessment/Control Technology Development Program, the Radian Corporation is currently conducting a 3-year program (March 1976 to March 1979) for the comprehensive environmental sampling/analysis tests at 4 low/medium Btu gasification facilities, including the Kosovo Kombinat plant in Pristina, Yugoslavia, which uses Lurgi gasifiers to convert lignite to fuel gas and fertilizer plant feedstocks. An environmental test plan for the Kosovo plant has been developed jointly by the Rudarski Institute (Belgrade, Yugoslavia), EPA, and Radian as part of a cooperative environmental research program. Radian is providing on-site technical assistance during the tests.

- University of North Carolina (UNC) and North Carolina State University (NCSU) - The UNC program on wastewater treatability and the NCSU program on raw/acid gas clean-up are discussed in Sections 5.5 and 3.2.5, respectively.

2.6.2 DOE-Sponsored Programs - Pilot Plants

Five contractors and two DOE national laboratories are currently involved in environmental assessment of five DOE high Btu gasification pilot plants. The five pilot plants and the environmental assessment coordinators for each plant are as follows:

Pilot Plant	Environmental Assessment Coordinator
Hygas	Institute of Gas Technology (IGT)
CO_2-Acceptor	Radian Corporation
Synthane	Pittsburgh Energy Research Center (PERC)
Slagging Fixed Bed	Grand Forks Energy Research Center (GFERC), Stearns-Roger, Inc.
Bigas	Phillips Petroleum, Penn. Environmental Consultants (PEC)

Carnegie-Mellon University (CMU) is providing overall coordination and evaluation for the entire DOE pilot plant assessment program. The status of the environmental assessments at each of the plants is summarized below:

- Hygas(22,23) - The DOE environmental assessment program at the Hygas pilot plant has been in effect since mid-1976 and a considerable amount of environmental data has been generated. Three on-line analytical instruments - a sulfur chromatograph, a total organic carbon (TOC) analyzer, and a total oxygen demand (TOD) analyzer for water streams - have been installed and operated in recent runs. A heated and insulated gas sampling line has been installed between the gasifier cyclone and pre-quench tower, for the sampling of raw product gas before water quench. Laboratory experiments to determine the effects of shift catalysts on trace constituents in the product gas are continuing. Batch and continuous leach tests have been performed on Hygas char. As the operation of the Hygas pilot plant continues, additional data are expected to be generated for the gasification of very high sulfur coals and for operating conditions aimed at achieving high carbon conversions.

- CO_2-Acceptor(24,25) - Radian Corporation and CMU prepared and executed a comprehensive test program for the CO_2-Acceptor pilot plant prior to plant shutdown in 1977. Extensive gas phase analyses, particularly for sulfur species such as H_2S, COS and CS_2, were conducted at the plant. Numerous analyses and time variability studies were also conducted on selected wastewater streams and constituents. Limited gas phase sulfur species data have also been collected by Stearns-Roger, Inc. (the plant operations contractor) during the last few plant runs. Results of both the Radian and the Stearns-Roger tests are soon to be published.

- Synthane(25,26) - Preliminary field work has been performed at the Synthane pilot plant as part of a comprehensive environmental assessment of the process. An ambient sampling program has been undertaken to determine baseline conditions as well as impacts caused by the operation of the plant. A process/waste stream sampling and analysis program is currently under way at the pilot plant. In a parallel effort, PERC is operating a bench-scale Synthane unit to generate supplementary data. Studies have been conducted on the biotreatability of the quench waters from the bench-scale unit and on the mechanism of tar and oil formation and decomposition.

- Slagging Gasifier(25,27) - At the Grand Forks Energy Research Center (GFERC) in Grand Forks, North Dakota, a preliminary comprehensive test plan for the slagging gasifier was developed by GFERC and Stearns-Roger, Inc. Analyses have been performed and results reported on the composition of product gases, condensates and slag produced when lignite was utilized as feed. Similar data are to be collected for other coals and under a variety of operating conditions.

- Bigas(25) - Penn. Environmental Consultants have developed a multimedia environmental sampling and analysis plan for the Bigas pilot plant. Limited sampling and analysis of selected Bigas condensates have been performed but the results have not yet been published. Testing under steady state conditions has been hampered by the continual operating difficulties encountered with the gasifier operation (see Section 2.3.3).

2.6.3 DOE-Sponsored Programs - National Laboratories and Other Programs

- Oak Ridge National Laboratory (ORNL)(28,29) - The DOE's Biomedical and Environmental Research Division (BERD) is currently conducting research to determine potential environmental/health problems stemming from coal conversion. In connection with the dry ash Lurgi process, a number of studies have been proposed and some are being implemented by BERD/ORNL relating to industrial hygiene and safety, epidemiological studies and procedures, pollutant monitoring techniques, and other environmental information. One such program which is currently underway involves characterization of the solid wastes generated at a Lurgi facility from the standpoint of trace element and organics composition. Another current program at ORNL involves the development of short-term genetic bioassay for characterization of complex effluents and the identification of chemical mutagens.

- Battelle-Pacific Northwest Laboratories (BNWL)(30) - BNWL is currently conducting a program to characterize products and waste streams from synfuels processes, including gasification processes. Although most of the effort to date has been directed toward the analysis of oil shale and coal liquefaction effluents, BNWL has conducted limited sampling and analysis at the CO_2-Acceptor pilot plant in Rapid City, South Dakota, and has analyzed effluents from the Laramie Energy Research Center in-situ coal gasification facility in Hanna, Wyoming. Data for the CO_2-Acceptor and in-situ testing have not yet been made public.

- Argonne National Laboratory (ANL)(31) - ANL has recently initiated a 5-year program to analyze trace organics in process streams at coal gasification pilot plants by means of gas chromatography-mass spectrometry (GC/MS). Effluents from high and low/medium Btu gasification operations are to be analyzed, beginning with condensates from the Hygas pilot plant in Chicago, Illinois. A parallel effort is being conducted for the biological characterization of various sample fractions to determine which fractions are carcinogenic or mutagenic using Ames cell tests.

- Slagging gasification tests at the Lurgi facility in Westfield, Scotland(6,32) - DOE has been sponsoring tests at the commercial-scale Lurgi plant in Westfield, Scotland, where a gasifier has been operated in the slagging mode. The project is being conducted by a consortium of companies headed by Conoco, Inc., in cooperation with the British Gas Corporation. Sampling and analysis of major process streams have been performed at the Westfield site.

The results of the Westfield tests are to serve as the basis for the Conoco design of a DOE-funded slagging Lurgi demonstration plant to be constructed in the U.S. A site at Noble County, Ohio has been proposed for the demonstration plant.

3.0 GAS PURIFICATION OPERATION

Figure 3-1 presents the process modules for the gas purification operation. As shown in this figure, the gas purification operation consists of two process modules: quench and dust removal and acid gas treatment. The quench and dust removal, which for many high Btu gasification systems is integrated into the design and operation of the gasifier, was reviewed in Section 2.0 in connection with the gasification operation. This section reviews the acid gas treatment module of the gas purification operation and discusses the various processes in this module.

3.1 REQUIREMENTS FOR ACID GAS REMOVAL

The removal of H_2S and trace sulfur species from raw product gas is necessary to prevent methanation catalyst poisoning. The removal of CO_2 is almost always necessary to obtain a product gas with heating value equivalent to that of natural gas. (In this respect, the acid gas treatment for CO_2 removal may also be considered an element of the gas upgrading operation - see Chapter 4.0.) Depending on the hydrogen to carbon monoxide ratio of the raw product gas, which determines whether or not shifting of the gas is necessary prior to methanation, the acid gas treatment may immediately follow quench and dust removal or it may follow gas shifting. H_2S and CO_2 may be removed either simultaneously ("non-selectively") or separately ("selectively"), depending on the specific acid gas removal process chosen and its design. The specific acid gas treatment process (selective or non-selective) to be used in a high Btu coal gasification plant should be chosen with due consideration to the integration of the process with sulfur recovery and/or tail gas treatment and the overall economics of the sulfur management scheme (see below.)

After shift conversion, the product gas from most gasification processes (dry ash Lurgi, Hygas steam-oxygen, Cogas, Synthane, and Bigas) contains about

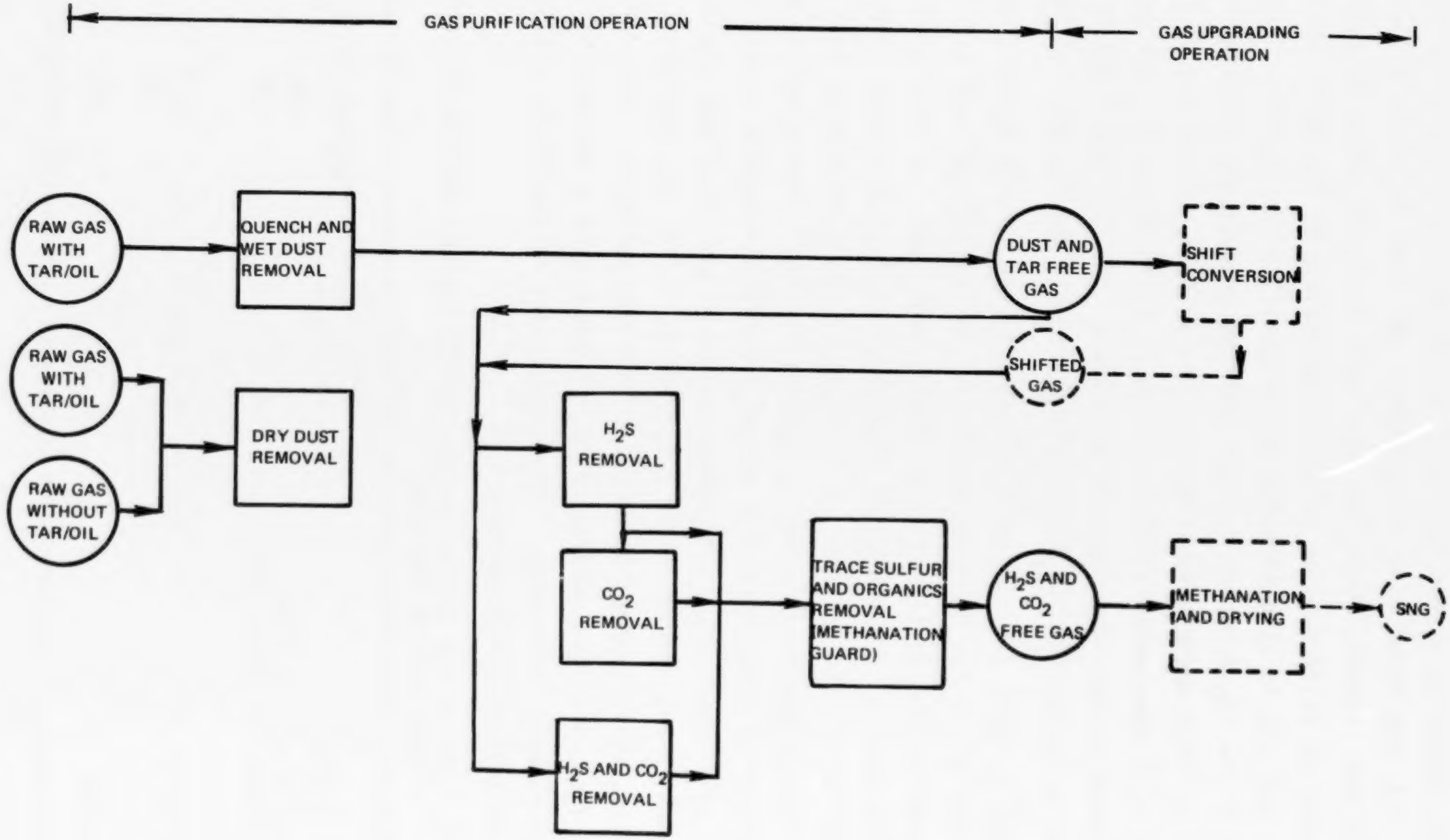

GAS PURIFICATION OPERATION
GAS UPGRADING OPERATION
RAW GAS WITH TAR/OIL
QUENCH AND WET DUST REMOVAL
DUST AND TAR FREE GAS
SHIFT CONVERSION
SHIFTED GAS
RAW GAS WITH TAR/OIL
RAW GAS WITHOUT TAR/OIL
DRY DUST REMOVAL
H_2S REMOVAL
CO_2 REMOVAL
H_2S AND CO_2 REMOVAL
TRACE SULFUR AND ORGANICS REMOVAL (METHANATION GUARD)
H_2S AND CO_2 FREE GAS
METHANATION AND DRYING
SNG

Figure 3-1. Process Modules for Gas Purification and Gas Upgrading Operations

30 to 35% CO_2, depending on the feed coal. (Considerably higher levels of CO_2, about 53 to 57%, are found in shifted product gas from the slagging Lurgi and considerably lower levels, about 10%, are found in CO_2-Acceptor product gas.) The H_2S content of shifted gases is determined mainly by the sulfur content of the feed coal and is also affected by the gasification process. Except in the case of the CO_2-Acceptor process, shifted product gas contains about 0.2 to 0.4% H_2S when western subbituminous coals (0.7% sulfur) are gasified and about 1 to 2% when eastern bituminous coals (2 to 4% sulfur) are gasified. The CO_2-Acceptor product gas contains only about 0.03 to 0.06% H_2S (and about 10% CO_2) due to sulfur (and CO_2) removal by dolomite during gasification.

As shown in Table 3-1, CO_2 to H_2S ratios in the shifted product gas vary from about 100 to 275 for the gasification of low sulfur coal and are in the 30 to 40 range for the gasification of high sulfur coal. As will be discussed in Chapter 5.0, processing of acid gases in a Claus sulfur recovery plant is inefficient and uneconomical when the acid gases contain less than 10-15% H_2S (corresponding to a CO_2 to H_2S ratio of 7). Non-selective acid gas treatment of shifted gases will generate a stream containing less than 10% H_2S and will hence require treatment by processes other than Claus (e.g., Stretford, which can handle dilute H_2S levels). Selective acid gas treatment processes, while generating an H_2S stream concentrated enough for use as Claus plant feed, may also generate a CO_2 stream having a residual H_2S too large for atmospheric discharge. Thus, additional treatment would also be required with selective H_2S removal.

TABLE 3-1. CO_2 TO H_2S RATIOS IN THE SHIFTED PRODUCT GAS FOR VARIOUS GASIFICATION PROCESSES

Process	Feed Coal Sulfur (%)	CO_2/H_2S Ratio
Dry Ash Lurgi, Hygas Steam-Oxygen, Cogas, Synthane, and Bigas	0.7	~100
	~3	~30
Slagging Lurgi	0.7	275
	~3	~40
CO_2-Acceptor	0.7	>200

3.2 ACID GAS REMOVAL PROCESSES

This section summarizes the available information relating to candidate acid gas removal processes and their applicability to high Btu gasification. The processes discussed fall into three general categories: hot gas H_2S removal processes, physical and chemical solvent processes, and methanation guards.

3.2.1 Hot Gas H_2S Removal

Potentially high overall thermal efficiencies are possible with hot gas H_2S removal between shift conversion and methanation. Several processes are currently under development for the removal of H_2S and other sulfur compounds from raw, hot gasifier gas (see Table 3-2). These processes generally use either a solid material or a molten salt to capture H_2S as sulfides. The spent sorbent may or may not be regenerable. None of these processes have yet reached the commercial stage and only limited data are available on their performance. Data sheets were not prepared for these processes because of the limited data availability and the fact that these processes are not expected to be commercially available on time for incorporation in the first generation of SNG plants in the United States.

TABLE 3-2. HOT GAS H_2S REMOVAL PROCESSES UNDER DEVELOPMENT

Removal Agent	Process Developer
Iron oxide (Fe_2O_3/Fe_3O_4)	Morgantown Energy Research Center Appleby-Frodingham Battelle-Columbus Babcock & Wilcox
Coal Ash	University of Kentucky
Molten Carbonate	Battelle-Northwest
Half-Calcined Dolomite ($CaO \cdot CaCO_3$)	Conoco

3.2.2 Solvent Processes for Acid Gas Removal

A variety of solvent processes are commercially available or under development for the removal of CO_2 and H_2S from gas streams. These processes use solvents or solutions for the removal of acid gases. Depending on the process, the spent solution is regenerated by heating, depressurization or oxidation. The regeneration results in the production of a concentrated by-product gas stream which can be processed for sulfur removal and/or recovery. Compared to the hot gas removal processes which can handle shifted product gas without cooling, solvent processes cannot be operated at high temperatures (about 400°K or 250°F) due to sorbent volatility. The solvent processes can either be selective or non-selective (see Section 3.1). Through modification in design, some processes (e.g., Benfield) can be operated in either mode.

Many of the solvent processes have been used in the purification of natural gas and (to a lesser extent) refinery and coke oven gases. A few processes have been used for the treatment of coal gasification product gas. The operating data for these processes, however, are very limited. For application to high Btu gasification, the most important characteristics of a given process are (1) operability at high pressures, (2) the levels of residual sulfur compounds and CO_2 obtainable in treated gas, (3) the ability to remove trace constituents, (4) capital and operating (utility) costs, (5) constraints which the process imposes on upstream and downstream processing, and (6) generation of hazardous wastes and waste disposal requirements.

Solvent processes for acid gas treatment may be broadly classified as physical solvent processes, chemical solvent processes (amine based and carbonate based), mixed solvent processes, and oxidation/reduction (redox) processes. A listing of important representative processes in each category and their key features is presented in Table 3-3 (data sheets for these processes are included in Appendix B). As shown in the table, physical solvents offer good selectivity for removal of H_2S over CO_2 and can remove other sulfur and nitrogen compounds, water vapor, and some organics. Physical solvents are most effective and economical when high partial pressures of acid gases are encountered. Amine solvents are generally less selective than physical solvents and have higher energy requirements for regeneration. As the partial pressure of acid gas in the gas stream increases, the economy of amine systems declines. Carbonate systems can be partially selective toward H_2S, are not degraded by sulfur and nitrogen compounds, and do not absorb organics to any appreciable extent. Moderate to high pressure is generally required for economical operation of carbonate systems. Mixed solvents show

TABLE 3-3. KEY FEATURES OF SOLVENT PROCESSES FOR ACID GAS REMOVAL

Process Name	Solvent/Reagent	Operating Pressure (acid gas partial pressure)	Selectivity		Component Distribution*							Solvent Losses (Replacement Requirement)	Utility Requirements†
			H_2S/CO_2	CO_2/HC	COS	CS_2	RSH	NH_3	HCN	Higher Organics	Water Vapor		
PHYSICAL SOLVENTS													
Rectisol	Methanol	High	Good	Poor	a,b	a,b	a,c,d	c,d	a,c,d	a,b,c,d	d	High	Moderate/low
Selexol	Dimethyl ether of polyethylene glycol	High	Good	Moderate	a,b	a,b	a,c,d	c,d	a,c,d	a,b,c,d	d	Low	Low
Purisol	N-methyl 2-pyrrolidone	High	Good	Moderate	a,b	a,b	a,d	a,d	a,c,d	a,b,c,d	d	Low	Low
Fluor solvent	Propylene carbonate	High	Moderate	Moderate	a,b	a,b	a,d	a,d	a,c,d	a,b,d	d	Low	Low
Estasolvan	Tri-n-butyl phosphate	High	Moderate	Moderate	a,b	a,b	a,d	a,d	a,c,d	a,b,d	d	Low	Low
CHEMICAL SOLVENTS													
Amine Solvents													
Sulfiban	Monoethanolamine (MEA)	Low	Poor	Good	e	e	a,b,d	a,d	e	a,d	d,g	High	Very high
MDEA	Methyl-diethanolamine	Low	Moderate	Good	a,b	a,b	a,b,d	a,d	e	a,d	d,g	Moderate	High
DEA	Diethanolamine	Low	Poor	Good	a,b	a,b	a,b,d	a,d	e	a,d	d,g	High	Very high
ADIP	Diisopropanolamine	Low	Poor	Good	a,b	a,b	a,b,d	a,d	e	a,d	d,g	Moderate	High
Fluor Econamine	Diglycolamine (DGA)	Low	Poor	Good	a,b	a,b	a,b,d	a,d	e	a,d	d,g	Low	High
Alkazid	Dimethyl or diethyl glycine	Low	Moderate	Good	f,g	f,g	d,g	a,d	e	a,d	d,g	Low	High
Carbonate Solvents													
Benfield	Potassium carbonate and diethanolamine	Moderate	Moderate	Excellent	f,g	f,g	f,g	a,d	f,a,d	g	g	Low	Moderate
Catacarb	Potassium carbonate and amine borates	Moderate	Moderate	Excellent	f,g	f,g	f,g	a,d	f,a,d	g	g	Low	Moderate
MIXED SOLVENTS													
Sulfinol	Cyclotetramethylene sulfone and diisopropanolamine	Moderate	Poor	Moderate	a,b	a,b	a,d	a,d	a,d	a,b,d	d,g	Low	Moderate
Amisol	Methanol and mono- or diethanolamine	Moderate	Poor	Moderate	a,b	a,b	a,d	a,d	a,d	a,b,d	d,g	High	Moderate
REDOX PROCESSES													
Giammarco-Vetrocoke	Potassium carbonate and arsenate/arsenite	Moderate	Good	Excellent	f,g	f,g	f,g	a,d	f,a,d	g	g	Low	Moderate
Stretford	Alkaline metavanadate and anthraquinone disulfonic acid	Moderate	Good ‡	Excellent	g	g	g	g	e	g	g	Low	Moderate

* a) with acid gas stream after simultaneous CO_2 and H_2S removal
b) with CO_2 stream after separate CO_2 and H_2S removal
c) with H_2S stream after separate CO_2 and H_2S removal
d) with aqueous or organic liquid phase prior to or integral with process
e) degrades solvent
f) hydrolyzes
g) remains with treated gas

†Depends on acid gas partial pressure, selective vs. non-selective design, and residual sulfur allowed; rating is for moderate to high pressure application with <10 ppm residual H_2S in treated gas.

‡Selectivity good, but high CO_2 lowers H_2S absorption rate and requires large systems for efficient H_2S removal.

low selectivity for H_2S over CO_2. Redox processes offer the potential for H_2S removal and sulfur recovery in a single operation. They, however, suffer from certain disadvantages such as solution degradation (e.g., via thiocyanate formation in Stretford solution), the use of hazardous solvents (e.g., arsenic compounds in the Giammarco-Vetrocoke process), and inefficient H_2S absorption from high CO_2 content gases (e.g., Stretford).

The selection of an acid gas treatment process for SNG application should take into account subsequent tail gas treating and/or for sulfur recovery processes. In addition, factors such as residual sulfur, CO_2, organics, and moisture levels in the treated gas influence the design of methanation and associated guard systems. Based on the detailed data presented in Appendix B and the results of several other studies evaluating acid gas treatment systems for coal gasification application,(33-36) the following conclusions can be drawn:

- Physical solvents are likely candidates for high pressure selective acid gas removal. Processes such as Rectisol and Selexol offer high selectivity toward H_2S and would be economical for high pressure operation. Residual sulfur and CO_2 levels obtained are consistent with methanation catalyst protection requirements (i.e., only small sulfur guard beds would be required). Also, water vapor and organics which can deactivate either the sulfur guard or the methanation catalyst are largely removed.

- Amine based processes are not likely to be commercially employed for bulk acid gas removal in SNG production. MEA and DEA suffer both excessive degradation and vaporization losses. Even the more stable and less volatile solvents (e.g., DIPA, DGA) are uneconomical at high pressures and are not selective enough toward H_2S. The use of such processes would result in an acid gas stream containing as low as 0.3% H_2S and the remainder CO_2. This presents a major problem for subsequent sulfur recovery/removal. One amine solvent ADIP) has been proposed for use in a commercial SNG facility for the purpose of recovery of hydrocarbons and concentration of H_2S from the concentrated acid gas stream from a physical solvent process (Rectisol)(9,37).

- Carbonate systems may have application for both selective and non-selective acid gas removal from product gases at moderate pressures. Carbonate systems can be more economical than physical solvent systems for moderate pressure applications. Carbonate systems are ineffective in removing organics and produce a gas which is saturated with moisture. The high moisture and organics content of treated gases may necessitate additional treatment prior to methanation.

- Mixed solvents (Sulfinol and Amisol) are not likely to be employed in SNG application, due to their relatively low H_2S removal efficiency (e.g., compared to the carbonate system), lack of selectivity and high solvent costs.

- Redox systems which would be suitable for "tail" gas treatment are not likely to be employed for acid gas removal from product gas in high Btu gasification. Capital and operating costs for Redox systems would be significantly higher than for amine, physical solvent, and carbonate systems handling the same volume of gas. This is despite the fact that separate recovery of sulfur is not required with Redox systems. Other disadvantages of the Redox system include excessive solution degradation when treating gases containing HCN (e.g., in the case of the Stretford process), inability to remove trace sulfur compounds (COS, CS_2, mercaptans) and organics (in the case of Stretford and Giammarco-Vetrocoke processes), and the use of hazardous solvents (e.g., use of arsenic in the Giammarco-Vetrocoke process solvent). It should be emphasized, however, that processes such as Stretford may find applications to the concentrated acid gas stream generated by other acid gas removal systems (see Chapter 5.0).

3.2.3 Methanation Guards

Although most processes for acid gas treatment remove sulfur compounds to ppm levels or lower, additional measures to protect the methanation catalyst against sulfur poisoning and carbon formation are required. Methanation guards are fixed beds of adsorbents which, when used ahead of the methanation catalyst bed, can provide the necessary protection by (1) removing traces of sulfur compounds under normal operating conditions, (2) providing for "standby" bulk sulfur removal capacity in case of the malfunction of the acid gas removal systems, and (3) removing olefins and aromatic hydrocarbons which can lead to carbon formation on the methanation catalyst.

Methanation guards are of four general types: metal oxide beds (zinc, iron or nickel), metal oxide impregnated activated carbon, activated carbon, and molecular sieves. Data sheets for these types of methanation guards (processes) are included in Appendix B. Table 3-4 summarizes the key features of each process. As indicated in the table, a ZnO bed can achieve the lowest H_2S (and COS) levels. The zinc oxide bed, however, is not regenerable and is deactivated by the presence of the moisture in the feed gas. Spent methanation catalyst (NiO), although deactivated as far as catalytic activity for methanation is concerned, has a considerable capacity for adsorption of sulfur compounds and can potentially be used as guard bed material.

TABLE 3-4. FEATURES OF METHANATION GUARDS

Process	Efficiency				Applicable at High Temperature	Is Bed Regenerable?	Relative Cost
	H_2S Removal	COS Removal	Organics Removal	Moisture Removal			
Metal Oxides							
ZnO	Very high	High	Low	Low	Yes	No	Low
Fe_2O_3/Fe_3O_4	High	?	Low	Low	Yes	Yes	Moderate
NiO*	High	High	Low	Low	Yes	No	Low
Metal Oxide Impregnated Carbon	High	High	High	Low	Yes†	Yes	High
Activated Carbon	Low	Low	High	Low	Yes†	Yes	High
Molecular Sieves	Moderate	Incomplete	Moderate	High	No‡	Yes	High

*Assumes the use of spent methanation catalyst as methanation guard.

†Organics may not be completely removed at high temperatures.

‡H_2S not completely removed at high temperature; moisture only partially removed at high temperature.

Metal oxide impregnated carbon offers capability for both organics and H_2S removal and can also be regenerated. The cost of the system, however, would be higher than the cost of the throw-away zinc oxide system. Activated carbon is ineffective for the removal of low molecular weight sulfur compounds (H_2S and COS) but is very effective in removing aromatics and olefins. Molecular sieves are ineffective for H_2S removal at high temperatures, but are effective for removing moisture.

In summary, ZnO appears to be the most likely candidate for trace sulfur removal applications, whereas the activated carbon and molecular sieve are suitable for the removal of organics and moisture, respectively.

3.3 DISCHARGE STREAMS

Acid gas treatment systems have three general types of discharge streams: treated gas, by-product concentrated acid gas(es), and waste sorbent. Treated gas composition will depend upon the process chosen, the particular design of the process, and the properties of the feed gas. Many of the candidate processes listed in Table 3-3 can achieve H_2S levels of a few ppmv or lower and CO_2 levels less than 1000 ppmv. Levels of other constituents in treated gas are process dependent (see Table 3-3 for the fates of various species). Nonselective removal processes result in the production of a by-product acid gas stream which contains less than about 3% H_2S; selective removal processes can produce an acid gas stream containing over 15% H_2S. The CO_2 stream from selective removal often contains some H_2S and other sulfur compounds.

Waste or spent sorbent is produced in many processes due to the requirement for periodic or continuous purging of the sorbent to maintain high removal efficiency. Sorbent waste streams are also generated as a result of leaks and accidental spills. During normal operation, certain constituents removed from the feed gas (e.g., particulates, moisture and organics) accumulate in the system, thus requiring periodic purging. Some of the trapped material can also cause direct sorbent degradation (e.g., in the Sulfiban process, carbonyl sulfide and mercaptans can bring about sorbent degradation by forming gums and sludges). In the case of certain solid bed systems, the entire bed must be replaced periodically due to the exhaustion of the sulfur absorbing capacity (e.g., formation of zinc sulfide in the case of zinc oxide beds).

3.4 DATA GAPS AND LIMITATIONS

Although considerable data are available for many acid gas treatment processes, in the majority of cases such data are for applications to natural gas, petroleum refinery and miscellaneous industrial processes other than coal gasification. Even in the very limited cases where the available data pertain to coal gasification, the specific designs used would not necessarily be employed in SNG applications. For example, the Rectisol unit in use at the Sasol gasification facility in South Africa is designed for maximum acid gas removal with no consideration for sulfur recovery or tail gas treatment. At this facility, by-product acid gas is incinerated. In contrast, in a commercial facility in the U.S. the by-product gas stream must be processed for sulfur recovery/pollution control and the Rectisol design must be modified accordingly. The estimated characteristics of discharge streams associated with acid gas treatment processes incorporated in the proposed designs for commercial gasification facilities in the U.S. are based largely upon conceptual design and not on actual operating experience. Further, since the specific design of a given system would be influenced by cost, utility, and overall efficiency considerations and hence would vary from plant to plant, the exact stream compositions are also expected to vary from plant to plant.

Since no commercial SNG facility is in operation in the U.S., actual data on the composition and properties of waste streams from acid gas treatment are currently unavailable. Any waste characterization program should place special emphasis on elucidating the fate of trace constituents (e.g., COS, mercaptans, HCN, trace elements) in the acid gas treatment processes.

3.5 RELATED PROGRAMS

A limited number of programs are under way or planned which could provide additional data relating to gas purification operations. Under an EPA grant, North Carolina State University will operate a general purpose coal gasification/gas cleaning facility. As part of the overall program, at least four absorption solvents for acid gas removal will be tested (cold methanol, hot potassium carbonate, monoethanolamine, and dimethylether of polyethylene glycol). The results of these tests are expected to generate useful data relating to the performance of acid gas removal systems in coal gasification applications and the characteristics of process/discharge streams. The Synthane pilot plant (see Sections 2.2 and 2.3) incorporates both Benfield and Stretford units. The Bigas pilot plant features a Selexol unit. Texaco, Inc. and the Electric Power Research Institute are currently involved in a pilot plant program to evaluate entrained coal gasification-combined cycle gas turbine systems for electric power generation. The pilot plant, which is located at the Texaco's Montebello Research Laboratory, Montebello, Ca., features a Selexol unit for removal of H_2S from product gas. Operation of this unit should result in the generation of important data pertaining to process performance in SNG applications. Finally, a commercial scale Stretford unit has been recently constructed at the Sasol plant in South Africa which offers the opportunity to assess the performance of Stretford process in handling low H_2S, high CO_2 gases.

4.0 GAS UPGRADING OPERATION

The processing of quenched product gases to produce SNG generally requires a shift conversion step, an acid gas removal step, and a methanation and drying step. Figure 3-1 depicts the generalized process modules for these treatment steps. As shown in the figure, quenched product gas may or may not require shift conversion, depending on the hydrogen to carbon monoxide ratio. After shift conversion, acid gas removal is required to protect the methanation catalyst from sulfur poisoning and to remove carbon dioxide which would dilute the final product gas. Finally, hydrogen and carbon oxides are catalytically reacted to form methane and water, with subsequent moisture removal. (See Section 2.1 for the chemistry of shift and methanation.)

Processes for acid gas treatment were discussed in Section 3.0 in connection with the gas purification operations. Shift conversion and methanation which constitute the gas upgrading operation are reviewed in this section.

4.1 SHIFT CONVERSION

4.1.1 Shift Conversion Catalysts

Although shift conversion can follow acid gas treatment, in SNG production it is desirable to have the shift before the acid gas treatment to avoid an additional acid gas treatment step for the removal of the CO_2 generated in the shift reaction.

The reaction of carbon monoxide and water vapor to form hydrogen and carbon dioxide is a mildly exothermic reaction which can be promoted by a variety of catalysts. For application to SNG production, the shift reaction is best conducted at moderate to high temperatures (greater than 500°K). Conventional copper-based low temperature shift catalysts used in petrochemical applications are generally deactivated by sulfur compounds in feed gases. "Sulfided" cobalt molybdate based catalysts, which are active at temperatures close to 500°K (441°F), are not affected by the presence of gaseous sulfur compounds (indeed, some H_2S is required to maintain the catalyst in the active state) . These high temperature catalysts have been proposed for SNG application.

To achieve the required minimum 3:1 hydrogen to carbon monoxide ratio using catalytic shifting, two approaches are possible: (1) sending the entire gas flow through the catalytic reactor and (2) sending a portion of the flow through the catalyst bed and combining the shifted and unshifted gases afterward to obtain the proper ratio. Based on equilibrium calculations (and actual operating experience), a hydrogen to carbon monoxide ratio of up to 10:1 can be obtained at about 550°K. To take advantage of such a high conversion ratio, the second approach, which entails cost savings associated with a smaller reactor size, is preferred. (The proposed commercial Lurgi SNG plant designs for the U.S. feature split-flow shift conversion.) Considerable work is currently under way to develop processes which would enable shift conversion and methanation to be carried out in a single processing step. These approaches to joint shift conversion/methanation are discussed in connection with methanation in Section 4.2.

4.1.2 Discharge Streams

The shift conversion operation produces three types of discharge streams: (1) product gas, (2) condensate and (3) spent catalyst. From an environmental standpoint, the effect of the shift catalyst on the minor constituents in feed gas is of special importance. Most cobalt molybdate-based catalysts are active for the hydrolysis of carbonyl sulfide and carbon disulfide.

$$COS + H_2O = H_2S + CO_2$$

$$CS_2 + 2H_2O = 2H_2S + CO_2$$

Quenched product gases from high Btu gasification processes contain COS in the 15 to 150 ppmv range (Section 2.3), with COS to H_2S ratios ranging from 0.02 to 0.15. Under equilibrium conditions and at a temperature close to 550°K (530°F) the COS to H_2S ratio in such gases would be about 0.002 (CS_2 to H_2S ratio would be very much lower), hence indicating that near complete conversion of COS to H_2S could be achieved with the use of proper catalyst. Tests with relatively "clean" simulated coal gases and using fresh sulfided

Co-Mo shift catalyst have indeed indicated that essentially complete conversion of COS (and CS_2) to H_2S can be realized. This degree of conversion, however, has not been realized in pilot plant tests with actual coal gases. In a commercial facility, the actual COS level in the shift conversion product would depend upon how closely the equilibrium is approached in the shift reaction and the fraction of the feed sent through the reactor. For example, in a split-flow configuration whereby only about 55% of the quenched product gas is passed through the shift reactor, reduction in the total COS concentration would be less than 55%.

Cobalt molybdate-based catalysts are also active for many hydrogenation reactions and thus olefins and aromatics may be partially converted to saturated organics in a shift reactor. As far as is known, shift catalysts do not affect other trace constituents such as ammonia and HCN. A catalyst bed may serve as a physical trap for suspended particulate matter (coal dust, char ash) and as a chemical trap for certain trace elements (e.g., Hg, As, Cd). Accumulated material may lead to eventual catalyst deactivation.

A process condensate may be formed when the shifted gas is cooled. This aqueous stream would contain small quantities of dissolved gases originally present in the gas phase (H_2, CH_4, CO, CO_2, H_2S) and possibly higher molecular weight organic compounds. However, no actual operating data are available on the composition and the quantity of the process condensate. Depending on the facility design, a shift reactor may actually be a net consumer of foul waters produced elsewhere in a gasification plant. Hot feed gas may be passed through foul waters to generate the steam required for the shift reaction.

The shift catalyst will eventually become deactivated and require replacement. The spent catalyst will likely contain char, ash, high molecular weight organics, and coal-derived trace elements. Due to the proprietary nature of catalysts, essentially no information is publicly available relating to the properties of the spent catalyst.

4.1.3 Data Gaps and Limitations and Related Programs

The data base for shift conversion in SNG applications is limited primarily because there are currently no commercial facilities. Bench and pilot scale operations have provided some data, but these are limited in scope.

Some specific data gaps relate to:

- The effect of the shift catalyst on trace constituents (COS, CS_2, mercaptans, thiophenes, NH_3, HCN)
- The composition of process condensate(s)
- The catalyst life and properties of spent catalyst

The fate of minor gas constituents in shift conversion is currently being investigated by the Institute of Gas Technology (Chicago) in bench-scale studies of the performance of various shift catalysts.

4.2 METHANATION AND DRYING

4.2.1 Process Principles

Methanation and drying are the final steps in the production of SNG from coal derived gases (see Section 2.1). Methanation involves the catalytic reaction of carbon oxides and hydrogen to form methane (and water). The reaction is usually carried out at a temperature between 590 to 760°K (600 to 900°F) and under high pressures (approximately 7 MPa or 1000 psia). The most effective catalysts used for methanation contain nickel, usually in the reduced state. Three types of catalyst bed designs which have been tested are (1) fixed bed of pellets containing catalyst or a catalyst coating on tube walls, (2) catalyst bed fluidized by feed gas, (3) catalyst solids suspended in a high temperature boiling liquid through which the feed gas is passed.

Fixed bed methanation technology is widely employed in applications other than SNG production and has also been demonstrated in one commercial SNG plant (Westfield, Scotland) and in two high Btu gasification pilot plants (Hygas and CO_2-Acceptor). Fluidized bed and liquid phase methanation are currently in the development and testing stage for application to SNG production. Appendix C contains data sheets on these approaches to catalytic methanation.

As noted in Section 4.1.1, a number of processes which combine shift conversion and methanation in a single step are currently under development. Two of these processes which have reached the pilot plant stage are the Thyssengas GmbH (West Germany) process and the Ralph M. Parson RM process. The Thyssengas process uses a fluidized bed of nickel-based catalyst and has been tested on feed gases having H_2 to CO ratios of 2:1 to 3:1. Near-equilibrium production of methane and carbon dioxide has been demonstrated. The catalyst bed is generally operated at a temperature in the 620°K to 700°K (650°F tp 930°F) range which is about the same as those used in conventional methanation.

The RM process uses a series of fixed beds, each operated at a progressively lower outlet temperature (1000°K to 713°K or 1350°F to 760°F). The processes which use a proprietary nickel based catalyst have been shown to be capable of a high degree of conversion of H_2 and CO to CH_4 and CO_2. Compared to separate shift conversion and methanation, the combination shift-methanation processes have the advantages of eliminating the separate shift conversion step and reducing the volume of gas from which CO_2 is to be removed. Since it is operated at higher temperatures, the following additional advantages have been claimed for the RM process: (1) elimination of recycle flows for the control of temperature across methanation catalyst; (2) production of more steam and at higher pressures; (3) reduction in carbon formation in the bed; and (4) less sensitivity of catalyst to sulfur and easier catalyst regeneration.

Drying of the methanated gas is usually accomplished in two stages: condensation for bulk moisture removal and sorption for the removal of residual moisture(7-10). The bulk moisture removal is achieved by cooling and heat recovery. Molecular sieves or solvents (e.g., ethylene glycol) are used for the removal of trace moisture which remains after cooling; the exhausted molecular sieves and the spent solvents are regenerated. The gas drying operations (condensation and trace moisture removal) are not unique to SNG production and are widely used in a number of other industries (e.g., natural gas purification).

4.2.2 Discharge Streams

In all methanation processes, four types of discharge streams are encountered: (1) product gas, (2) condensed moisture, (3) emissions from catalyst decommissioning, and (4) spent catalyst. Product gas will be essentially free of particulate matter and sulfur and nitrogen compounds but will contain traces of carbon monoxide and hydrogen and possibly of nickel carbonyl and particulate nickel. Condensates formed by cooling of methanator product gas are generally free of dissolved and suspended solids and gases such as H_2S and NH_3, and are therefore suitable for boiler feed water or other uses where high quality water is required.

From an environmental standpoint, the major hazards associated with catalytic methanation arise during transient operations. At temperatures less than 480°K (400°F), carbon monoxide can react with reduced nickel catalyst to form nickel carbonyl. Methanation is ordinarily conducted at temperatures above 590°K (600°F); however, temperatures of less than 480°K (400°F) are encountered during start-up and shut-down. Inert gas (e.g., N_2, CO_2) must be used during heating and cooling to exclude carbon monoxide from the bed. Since reduced nickel catalyst is pyrophoric, a spent bed is commonly decommissioned by slowly adding air or oxygen to the cooled catalyst to initiate oxidation. The controlled oxidation of spent catalyst may result in an off-gas containing particulate matter, sulfur compounds, organometallic compounds, and carbon monoxide. "Burned" catalyst, although chemically more stable, still presents a hazard due to the potential toxicity of nickel. One likely use of oxidized spent catalyst is as methanation guards for sulfur removal (see Section 3.2.3). The disposal of spent catalyst is discussed in Section 7.1.2.

4.2.3 Data Gaps and Limitations and Related Programs

The operating experience with methanators in SNG applications is very limited. Essentially no data are available on emissions from decommissioning spent catalyst and on the properties of the spent catalysts. It is anticipated that additional engineering performance data will become available as a result of ongoing tests at the Hygas pilot plant (fixed and liquid phase methanation) and at the Bigas plant (fluidized bed methanation). The continuation of developmental work on combined shift conversion-methanation is expected to generate additional engineering and environmental data on this promising approach. The proprietary nature of methanation catalysts is a major roadblock to a more thorough investigation of emissions and hazards associated with the technology.

5.0 AIR POLLUTION CONTROL

This section reviews the sources and characteristics of gaseous waste streams associated with (a) the gasification, gas purification and gas upgrading operations described in Sections 2, 3 and 4; (b) water pollution control and solid waste management discussed in Sections 6 and 7; and (c) other auxiliary processes which are unique to the operation of integrated commercial high Btu gasification facilities. Processes which have been used for or may have application to the control of gaseous emissions in gasification facilities are reviewed and alternative control strategies for integrated facilities are discussed. Finally, the limitations of the existing data which prevent adequate definition of the applicability of available control technologies to gasification sources and the related programs which may supply some of the needed data are discussed. Detailed information on the individual air pollution control processes reviewed are presented in the "data sheets" contained in Appendix D.

5.1 SOURCES AND CHARACTERISTICS OF GASEOUS EMISSIONS

Figure 5-1 identifies the general sources of air pollution in a high Btu gasification plant. As indicated in this figure, six types of gaseous waste streams might be identified in a commercial gasification facility. These are: (1) pretreatment off-gases, (2) lockhopper vent gases, (3) concentrated acid gases, (4) catalyst regeneration/decommissioning off-gases, (5) char combustion, incineration and transient waste gases, and (6) depressurization, stripping and vent gases. As noted below, not all of these waste stream types are associated with all high Btu gasification processes and very limited data are available on the composition of these gas streams. Table 5-1 presents some composition data which have been reported for six stream types from the CO_2-Acceptor, Hygas and Lurgi processes based on actual operation. A discussion of these data and the limited available information (mostly qualitative in nature) on other gaseous waste streams follows.

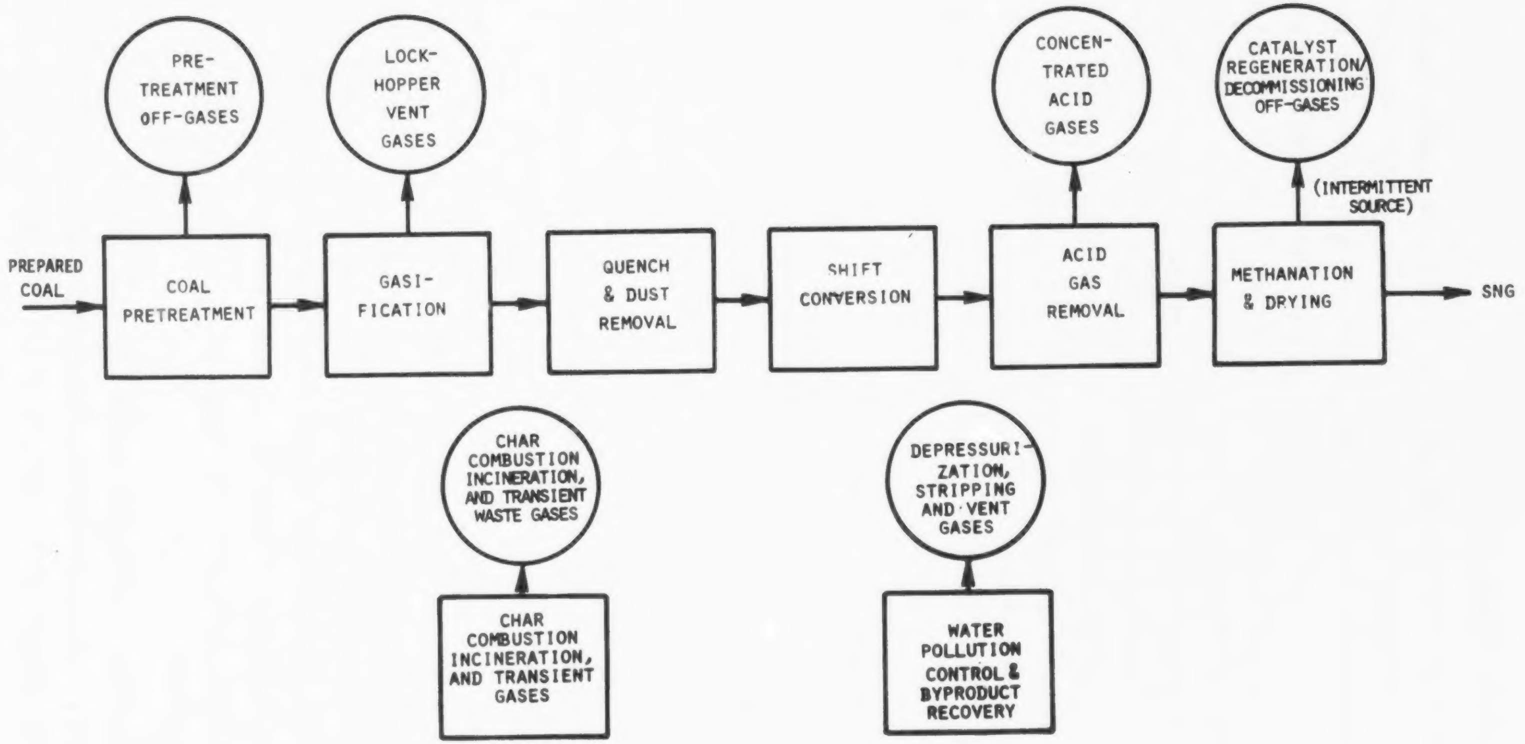

PREPARED COAL
COAL PRETREATMENT
PRE-TREATMENT OFF-GASES
GASI-FICATION
LOCK-HOPPER VENT GASES
QUENCH & DUST REMOVAL
SHIFT CONVERSION
ACID GAS REMOVAL
CONCEN-TRATED ACID GASES
METHANATION & DRYING
CATALYST REGENERATION/DECOMMISSIONING OFF-GASES
(INTERMITTENT SOURCE)
SNG
CHAR COMBUSTION INCINERATION, AND TRANSIENT WASTE GASES
CHAR COMBUSTION INCINERATION, AND TRANSIENT GASES
DEPRESSURI-ZATION, STRIPPING AND VENT GASES
WATER POLLUTION CONTROL & BYPRODUCT RECOVERY

Figure 5-1. Process Modules Generating Gaseous Wastes in a Typical High Btu Gasification Plant

5.1.1 Pretreatment Off-Gases

Except for Bigas and Hydrane processes, high Btu gasification processes cannot directly handle strongly caking coals. For these processes, caking coals must be pretreated, usually with steam and air to destroy caking tendencies. When caking coals are to be gasified and the coal pretreatment is carried out in a vessel external to the gasifier (e.g., in the Hygas pilot plant in Chicago), a flue gas is generated which contains coal pyrolysis and partial oxidation products as well as particulate matter. It should be noted, however, that all the proposed commercial facilities are designed to handle subbituminous or lignitic coals which are essentially noncaking. To date, the only available data on pretreatment off-gas are for the Hygas pilot plant. Even for this plant, the available data are limited to the concentration of major constituents (see Table 5-1) and to sulfur mass balance around the pretreatment unit. The mass balance data indicate that up to 25% of the sulfur in feed coal may be volatilized as a result of pretreatment. The volatilized sulfur is discharged in the pretreatment off-gas. In a commercial facility the fuel value of such off-gas would likely be recovered by combustion and the resulting flue gas treated for SO_2 and particulate removal.

5.1.2 Lockhopper Vent Gases

This waste stream is associated with those processes which use lockhoppers for coal feeding and ash discharge. Essentially no actual operating data are available on the composition of this waste stream.

As noted in Section 2.4.1, the feed lockhopper may be pressurized with either the product gas or with the CO_2 stream from acid gas treatment. In the former case, the lockhopper vent gas would contain components of the product gas plus coal devolatilization products and particulates. In the latter case, the vent gas would contain coal devolatilization products, some gasifier gas components and components originally present in the CO_2 gas stream (e.g., COS, H_2S). In both cases, the vent gas requires treatment for particulate, sulfur and hydrocarbon control.

The ash lockhopper, commonly pressurized with steam, generates an off-gas which would contain particulates and components of the gasifier gas. This off-gas would require treatment for particulates and odor control before discharge.

TABLE 5-1. COMPOSITION OF GASEOUS WASTE STREAMS

Constituents	Pretreatment Off-Gas*	Concentrated Acid Gases			Char Combustion Gas§	Depressurization Off-Gas**		Stripper Off-Gas††	Oil Storage Vent Gas‡‡
		Selective†							
		H_2S Stream	CO_2 Stream	Non-Selective‡		Tar Sep.	Oil Sep.		
H_2S	-	31%v	5 ppmv	0.9%v	28-320 ppmv	3.8-6.2%v	5.5-8.6%v	0.1%v	0.6%v
COS	-	0.8%v	8 ppmv	30 ppmv	46-150 ppmv	--	--	--	--
CS_2	-	--	--	2 ppmv	--	--	--	--	--
NH_3	-	--	--	--	--	1.0-6.3%v	1.8-12%v	--	--
SO_2	-	--	--	--	92-121 ppmv	--	--	--	--
CO_2	3.8-5.0	68%v	80%v	97%v	28-29%v	63-85%v	59-86%v	58.1%v	67.3%v
CO	1.5-4.0	--	0.14%v	--	2.0-2.2%v	1.5-5.9%v	0.8-4.7%v	0.7%v	1.4%v
H_2	0.06-0.4	--	0.33%v	0.14%v	68%v	2.9-11.7%v	2.3-9.6%v	10.9%v	9.0%v
N_2+Ar	2-2.5	--	19%v	0.03%v	--	1.0-8.0%v	1.0-6.4%v	20%v	5.3%v
CH_4	0.16-0.55	--	--	0.9%v	--	1.8-5.3%v	1.2-4.2%v	8%v	10.9%v
C_2H_6	-	--	--	--	--	--	--	0.64%v	1.1%v
C_3H_8	-	--	--	--	--	--	--	0.23%v	0.44%v
C_4H_{10}	-	--	--	--	--	--	--	0.17%v	0.43%v
C_5+	-	--	--	--	--	--	--	--	0.3%v

*Pretreatment of Ill. #6 coal at Hygas pilot plant; see data sheet in Appendix A.

†Selective Rectisol unit used in conjunction with an oil gasification plant using the Texaco partial oxidation process; see Appendix B.

‡Non-selective Rectisol unit used in Lurgi coal gasification facility in Sasol, South Africa; see Appendix B.

§Scrubbed flue gas from char combustion in the CO_2-Acceptor process; see data sheet in Appendix A.

**Oil-water separator flash gas for dry ash Lurgi process; see data sheet in Appendix A.

††Vent gas from the oil stripper at the Hygas pilot plant; see data sheet in Appendix A.

‡‡Hygas product oil at the pilot plant, see data sheet in Appendix A.

5.1.3 Concentrated Acid Gases

As discussed in Section 3.1, concentrated acid gas streams result from the processing of the raw or shifted product gas to remove H_2S and/or CO_2. The composition of acid gas(es) in a high Btu gasification plant will depend upon raw product gas composition and the type of acid gas treatment process employed. Although a large number of processes are available for the removal of acid gas, and many of them are in commercial use in industries such as natural gas, petroleum refining and by-product coke, only a few processes have been used for the treatment of raw product gas from coal gasification. Examples of processes which have been used on coal gasification raw product gas are Rectisol, Benfield and Sulfinol. For these applications, the recovered concentrated acid gases have been flared, and the acid gas treatment systems have not been tailored for sulfur recovery/removal which would be required in an operating commercial facility in the U.S. While a limited amount of data is available on the Rectisol process, no composition data have been reported on the concentrated acid gas streams from Benfield and Sulfinol processes in a coal gasification application.

Table 5-1 presents representative data on the concentrated acid gas streams from the Rectisol process operated in selective (separate H_2S and CO_2 removal) and nonselective (combined H_2S and CO_2 removal) modes. The data for the nonselective system are for an actual application to coal gasification raw product gas processing. The indicated levels of H_2S and CO_2 (0.5% and 97%v, respectively) are probably representative of the levels which would be expected in the concentrated acid gas stream from application of nonselective acid gas treatment systems to the processing of raw product gas from the gasification of low to medium sulfur coals. The data for the selective Rectisol process shown in Table 5-1 are for an oil gasification application and probably give an approximate indication of the degree of separation of H_2S and CO_2 which can be achieved in a selective acid gas removal system. The levels of constituents other than H_2S and CO_2 in the concentrated acid gas stream(s), however, would most likely vary greatly depending upon the specific acid gas treatment process used. For example, the data in Table 5-1 indicate a relatively large COS concentration in the concentrated H_2S stream for the selective Rectisol process. In the Benfield process the COS is largely destroyed (hydrolyzed) in the sorbent solution, and in the Selexol process the COS which is removed is discharged in the CO_2-rich stream. Depending on the process used, concentrated acid gas streams may contain hydrocarbons, traces of sorbents, carbon disulfide, mercaptans, hydrogen cyanide and ammonia. Little quantitative data are available for these constituents.

5.1.4 Catalyst Regeneration/Decommissioning Off-Gas

As discussed in Section 4.2.2, off-gases would arise from the decommissioning of spent methanation catalyst prior to direct reuse (as methanation guard), regeneration or disposal. The decommissioning involves controlled oxidation with air; the resulting off-gas contains sulfur compounds, particulate matter, carbon monoxide and (perhaps) traces of organometallic compounds. Because of the proprietary nature of the methanation catalyst and its handling procedure, no data have been published on the characteristics of such off-gases.

Also, little information is available on the regeneration procedures (if any) for the catalyst, on any emission which might be associated with such regeneration, and on whether in a commercial facility the regeneration will be performed on-site or off-site. The emissions associated with catalyst decommissioning and regeneration (or reclamation) are expected to be small in volume and of infrequent nature.

5.1.5 Char Combustion, Incineration and Transient Waste Gases

Several potential sources of combustion emissions may be associated with coal gasification facilities. Those processes which feature external char combustion (e.g., CO_2-Acceptor, Synthane and Cogas) generate a flue gas from this source. Typical data which have been reported for the CO_2-Acceptor char combustion flue gas after alkaline scrubbing are presented in Table 5-1. The data indicate that the treated flue gas contains significant quantities of CO (about 2%) and relatively high concentrations of reduced sulfur compounds. No data are available on the composition of the untreated flue gas from this process or on the composition of flue gases from the combustion of chars from other gasification processes. These flue gases are expected to contain SO_x, particulates, NO_x and trace elements (both in particulate and gaseous forms).

Many of the carbonaceous wastes generated in a coal gasification facility may be disposed of by incineration. Examples of such wastes are tars and oils from quench systems, sludges from wastewater treatment operation and waste gases from thermal regeneration of activated carbons (used for hydrocarbon removal from process and waste gases and in water pollution control). At the present time, there are no known applications of incineration for the disposal of carbonaceous wastes (other than tars and oils) generated in a gasification facility. The composition of incineration flue gas would vary with the waste and the incineration design.

Raw product gas and gases from other operations (e.g., acid gas treatment and gas stripping) which are produced during the start-up and shut-down operations and as a result of "upset" conditions are waste gases requiring treatment and disposal. The compositions and volumes of these gases would be highly variable depending on the source and the transient conditions. These gases would generally be expected to contain at least some of the components which are present in the gases produced during steady state operation.

5.1.6 Depressurization, Stripping, and Vent Gases

When aqueous or organic condensates have been produced under pressure (e.g., as a result of raw product gas quenching) and are subsequently depressurized (e.g., for the separation and recovery of tars and oils and for wastewater treatment), an off-gas is generated which contains some of the volatile components and gases originally dissolved or contained in the liquid phase(s). The major components of such off-gases are carbon dioxide, carbon monoxide, hydrogen sulfide, ammonia, hydrogen and low molecular weight organics (e.g., methane). Table 5-1 contains data on the composition of depressurization gases associated with tar and oil separation from dry ash Lurgi quench condensates. The data indicate that these particular off-gases contain significant quantities of H_2S and NH_3. No information is available on the minor constituents (e.g., COS and HCN) which may be present in these off-gases. Also, no data are available on the composition of depressurization gases from processes other than Lurgi.

In the treatment of aqueous or oily condensates for the recovery of hydrogen sulfide, ammonia and/or organics by distillation or gas stripping, an off-gas is generated which contains these and other volatile and gaseous compounds (e.g., HCN, CO, CO_2, CH_4 and COS). Aqueous condensates ("sour" waters) are commonly stripped with steam to remove both H_2S and NH_3. Depending upon the concentrations in the feed and the stripper design, relatively concentrated separate H_2S and NH_3 streams can be obtained. Steam stripping can generally result in the removal of greater than 99% of the H_2S and 95% of the ammonia in the sour water feed. No data are available on the actual composition of the stripper off-gas in applications to sour waters from coal gasification. Data on the composition of the off-gas from the nitrogen stripping of condensed oils at the Hygas pilot plant are presented in Table 5-1. At this pilot plant the stripping is aimed at the recovery of the light oil fraction, some of which is used to prepare coal slurries for feeding to the gasifier. As indicated in the table, the stripping off-gas from this particular application contains CO_2, small amounts of CO, H_2S, and low molecular weight hydrocarbons.

For those processes which generate tars and/or oils during gasification and which recover such materials for sale or recycle, evaporative emissions may be associated with storage of such materials. Such evaporative emissions are usually in the form of vent gases from storage facilities. The vent gases generally contain the same constituents as are present in the stored material. The concentrations of these constituents in the gas phase are determined by the corresponding concentrations in the liquid phase, their volatility and the temperature. Table 5-1 presents data on the composition of the oil storage vent gas for the Hygas process. As noted in the table, this particular vent gas contains significant concentrations of CO_2, CH_4 (and other low molecular weight hydrocarbons), CO, and H_2S.

5.2 AIR POLLUTION CONTROL PROCESSES

Since no commercial high Btu gasification facility currently exists and many of the gasification and gas purification and upgrading processes are in early developmental stages, with very few exceptions the processes which may be applicable to the control of gaseous emissions from coal conversion facilities have not been tested in such applications. Even though many of the control processes have been used in similar applications in other industries (primarily in the petroleum refining, coke and natural gas industries), essentially little or no engineering and operating data are available on such processes for applications to coal gasification. In this section, the air pollution control processes which have been tested in coal gasification applications or which may be potentially suitable for such applications are reviewed. The air pollution control options and strategies for integrated facilities are reviewed in Section 5.3.

Figure 5-2 presents the process modules for the control of gaseous waste streams discussed in Section 5-1. The process modules shown in the figure are for sulfur recovery; tail gas treatment for additional H_2S or sulfur recovery; SO_2 control and/or recovery; incineration; particulate control; CO, hydrocarbon and odor control; gas compression and recycling; and NO_x control. Each module consists of a number of interchangeable processes or processes which would be applicable to a range of conditions. The processes which are discussed in connection with each module are listed in Table 5-2.

TABLE 5-2. AIR POLLUTION CONTROL PROCESSES REVIEWED FOR APPLICATION TO HIGH BTU GASIFICATION

Sulfur Recovery	Claus, Stretford, Giammarco-Vetrocoke
Tail Gas Treatment	SCOT, Beavon, IFP-1, IFP-2, Sulfreen, Cleanair
SO_2 Control and/or Recovery	Wellman-Lord, Chiyoda Thoroughbred 101, Shell copper oxide, lime/limestone slurry scrubbing, double alkali, and magnesium oxide scrubbing
Incineration	Thermal oxidation, catalytic oxidation,
CO, Hydrocarbon and Odor Control	Thermal oxidation, catalytic oxidation, activated carbon absorption
Particulate Control	Fabric filter, electrostatic precipitation, venturi scrubbing, cyclones
Compression and Recycling	Compression and recycling
NO_x Control	Combustion modification and dry and wet processes

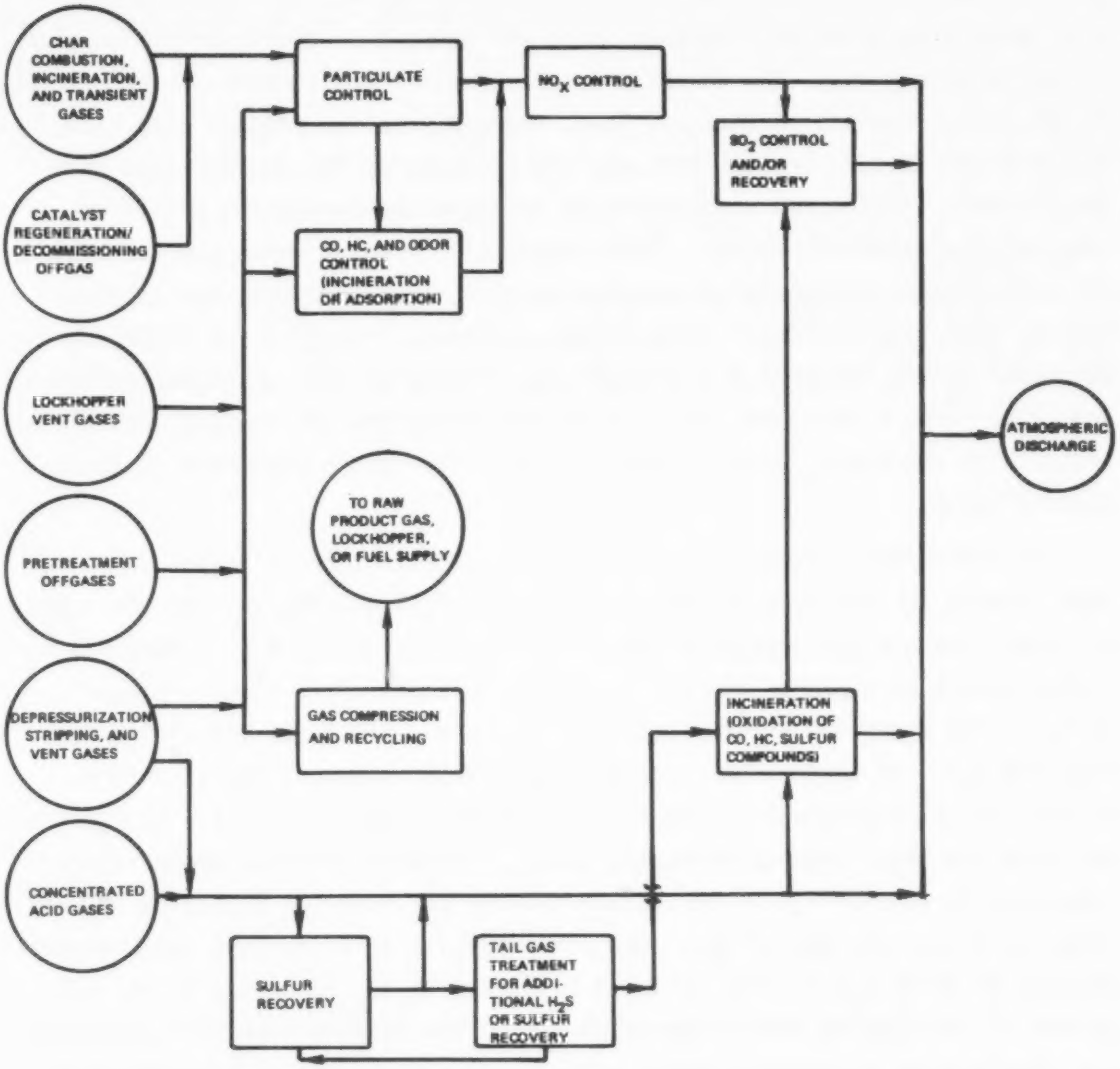

CHAR COMBUSTION, INCINERATION, AND TRANSIENT GASES
CATALYST REGENERATION/ DECOMMISSIONING OFFGAS
LOCKHOPPER VENT GASES
PRETREATMENT OFFGASES
DEPRESSURIZATION STRIPPING, AND VENT GASES
CONCENTRATED ACID GASES
PARTICULATE CONTROL
CO, HC, AND ODOR CONTROL (INCINERATION OR ADSORPTION)
NO_X CONTROL
SO_2 CONTROL AND/OR RECOVERY
TO RAW PRODUCT GAS, LOCKHOPPER, OR FUEL SUPPLY
GAS COMPRESSION AND RECYCLING
INCINERATION (OXIDATION OF CO, HC, SULFUR COMPOUNDS)
ATMOSPHERIC DISCHARGE
SULFUR RECOVERY
TAIL GAS TREATMENT FOR ADDITIONAL H_2S OR SULFUR RECOVERY

Figure 5-2. Process Module for Air Pollution Control
(see Figure 5-1 for sources of gaseous wastes)

5.2.1 Sulfur Recovery

Two gaseous streams which contain sufficiently high concentrations of H_2S and other sulfur compounds to justify sulfur recovery are concentrated acid gases from acid gas treatment units and gases from depressurization and stripping operations. The characteristics of these two streams are determined by the sulfur content of the coal feed, the gasification process used, and the acid gas removal process employed (in the case of the concentrated acid gas stream). Sulfur recovery generally involves the conversion of sulfur compounds to elemental sulfur. Of a number of processes which are available for sulfur recovery, three are considered to be most promising for application to coal gasification. These three are Claus, Stretford and Giammarco-Vetrocoke (G-V), and have been widely used in natural gas, petroleum refinery and/or by-product coke industry. Table 5-3 summarizes the key features of these three processes, based on the detailed information presented in Appendices B and D.

As indicated in Table 5-3, the Claus process is generally applicable to feed streams containing a minimum of 10% - 15% H_2S, whereas the Stretford and G-V processes are applicable to feeds containing around 1% H_2S. (Some Claus plants have been designed and are operating on feeds containing as low as 5% H_2S. The Stretford process has also been used with feeds containing more than 10% H_2S. At these high concentration levels, however, the Stretford process is not economically competitive with the Claus process.) The treated gas from the Claus process generally contains several thousand ppm of sulfur compounds (primarily H_2S), whereas the treated gas from the Stretford and G-V contains only a few ppm of H_2S. The Claus process is a dry high temperature process in which H_2S is catalytically reacted with SO_2 (produced by air oxidation of the H_2S) to form elemental sulfur. The Stretford and G-V processes are liquid-phase oxidation systems using aqueous solutions of alkaline metavanadate/anthraquinone disulfonic acid and arsenite, respectively. While other reduced forms of sulfur (e.g., CS_2 and COS) are partially removed by the Claus and G-V processes, they are not removed by the Stretford process. Since the Claus process operates at a relatively high temperature it is also capable of oxidizing some of the hydrocarbons.

TABLE 5-3. GENERAL CHARACTERISTICS OF SULFUR RECOVERY PROCESSES

Process	Process Principle	Limits of Applicability	Control Efficiencies (%)						By-Product	Effect of CO_2	Commercial Applications
			H_2S	COS/CS_2	R-SH	HCN	NH_3	HC			
Claus	Catalytic oxidation of H_2S to elemental sulfur	Straight-through system utilized for higher H_2S concentrations. Split-stream system utilized for H_2S concentrations of 10%-15%. Sulfur-burning mode used for H_2S levels down to 5%.	90 - 95	90	95	Partially oxidized	Partially oxidized	90	Elemental liquid sulfur	Can adversely affect sulfur removal ability and therefore increase plant size. If CO_2 exceeds 30% and NH_3 exceeds 500 ppmv, catalyst plugging problems may occur.	Widely employed in petroleum refinery, natural gas, and by-product coke industry. One known application to coal gasification in South Africa.
Stretford	Liquid phase oxidation of H_2S to elemental sulfur in an alkaline solution of metavanadate and anthraquinone disulfonic acid (ADA) salts.	Present applications are generally for 1% sulfur or less.	99.9 or greater	0	0	~100 (converted to SCN^- in Stretford solution)	0	0	Elemental sulfur	High CO_2 concentrations will decrease absorption efficiency by lowering solution alkalinity. Increasing absorber tower height and base addition are required.	Primarily natural gas service, a few applications to petroleum refining and by-product coke industries. A unit has been constructed at the Lurgi gasification facility at Sasol, So. Africa.
Giammarco-Vetrocoke (G-V)	Liquid phase oxidation of H_2S to elemental sulfur in potassium carbonate and arsenate/arsenic alkaline solution. A concentrated CO_2 stream with very low H_2S concentration is produced.	Maximum of 1.5% H_2S in feed stream.	99.99	Partially removed	Partially removed	?	0	0	Elemental sulfur which may require arsenic removal	Little or no effect. Process can be designed to selectively remove H_2S with low CO_2 absorption.	Primarily natural gas service; a few applications for hydrogen purification in petroleum refining and ammonia production.

Unlike natural gas and refinery acid gases which do not usually contain high levels of CO_2, concentrated acid gases and depressurization and stripping gases from coal gasification will contain high levels of CO_2. In the Claus process, high CO_2 concentration levels in the feed gas (greater than 30%v) would not create a major problem unless the gas also contained more than 500 ppmv of ammonia. In the Stretford process, high levels of CO_2 in the feed gas would reduce the alkalinity of the sorbent and, hence, reduce the system efficiency. Thus, where high CO_2 levels are encountered, larger absorption towers would be required to obtain high H_2S removal efficiency. In the G-V process, CO_2 is partially removed by the sorbent, but the absorption of CO_2 does not significantly impair the H_2S removal efficiency.

5.2.2 Tail Gas Treatment

Depending on the influent gas characteristics and the specific sulfur recovery process employed, the treated gas from a sulfur recovery system may require additional treatment before discharge to the atmosphere. Such additional ("tail gas") treatment may be necessary to achieve a higher level of H_2S removal (e.g., when the Claus process is used for sulfur recovery) and/or for the removal of hydrocarbon and other forms of sulfur (e.g., COS, CS_2, etc.). As with most of the sulfur recovery processes, the tail gas removal systems have not been used in connection with coal gasification, but many of them have been used in other industries (primarily in the petroleum refining industry).

Table 5-4 summarizes the key features of the sulfur recovery tail gas treatment processes. The processes listed in this table fall into three general categories: (1) processes such as IFP-1 and Sulfreen which are essentially extensions of the Claus process, (2) processes such as Beavon, Cleanair and SCOT which catalytically reduce the more oxidized sulfur compounds (e.g., SO_2, CS_2 and COS) to hydrogen sulfide which is recycled to the sulfur recovery systems, and (3) processes such as Chiyoda Thoroughbred 101, Wellman-Lord, IFP-2 and Shell CuO which involve the removal of SO_2 by scrubbing and require that the input gas be incinerated to convert all sulfur compounds to SO_2.

The processes in the first category have been employed exclusively for Claus plant tail gas treatment and are capable of reducing the sulfur level

TABLE 5-4. KEY FEATURES OF SULFUR RECOVERY TAIL GAS TREATMENT PROCESSES

Tail Gas Removal Process	Process Principle	Feed Stream Requirements/ Restrictions	Sorbents/ Solvents	Product	Utility Requirements	COS and CS_2 Removal	Efficiency	Effect of CO_2 in Feed Gas
Chiyoda Thoroughbred 101	Thermal oxidation of sulfur compounds to SO_2, followed by liquid absorption	Incinerated Claus tail gas; no specific requirement on $H_2S:SO_2$ ratio	2% (by wt.) sulfuric acid solution	Gypsum ($CaSO_4 \cdot 2H_2O$) 5 to 20% moisture content	Very high	Largely oxidized by incineration, not absorbed by solution	95% SO_2 or less than 300 ppmv	No effect
Beavon	Catalytic reduction of sulfur compounds to H_2S, followed by Stretford process	Sulfur recovery process tail gas is heated upstream of catalytic reactor; no specific $H_2S:SO_2$ ratio required	Stretford Process solution	Elemental sulfur	Low	Catalytically converted to H_2S	99.8% removal for Claus tail gas containing 4% equivalent H_2S	Reduces conversion efficiency by catalyst; decreases H_2S absorption by Stretford solution
Cleanair	Catalytic reduction of sulfur compounds to H_2S, followed by a continuation of the Claus reaction and Stretford process	$H_2S:SO_2$ ratio can vary up to 8:1 without affecting efficiency; designed specifically for Claus tail gas	Unknown aqueous solution and Stretford process solution	Elemental sulfur	Very low	Catalytically converted to H_2S	Plant effluent normally guaranteed to contain less than 250 to 300 ppm SO_2 equivalent	Reduces conversion efficiency of catalyst; decreases H_2S absorption by Stretford solution
IFP-1	Liquid phase continuation of Claus reaction at a low temperature	$H_2S:SO_2$ ratio maintained in the range of 2.0 to 2.4	Polyalkaline glycol	Elemental liquid sulfur	Very low	Not removed in catalytic reactor	Capable of reducing sulfur species in Claus tail gas to 2000 ppm as SO_2	No effect
IFP-2	Incineration of tail gas followed by ammonia scrubbing. Solution is evaporated to produce a concentrated SO_2 stream which is returned to the Claus plant.	$H_2S:SO_2$ ratio maintained in the range of 2.0 to 2.4	Aqueous ammonia solution	Elemental liquid sulfur	High	Oxidized by incineration, not removed in catalytic reactor	Capable of reducing sulfur species in Claus tail gas to less than 500 ppm	No effect

(continued)

TABLE 5-4. CONTINUED

Tail Gas Removal Process	Process Principle	Feed Stream Requirements/ Restrictions	Sorbents/ Solvents	Product	Utility Requirements	COS and CS_2 Removal	Efficiency	Effect of CO_2 in Feed Gas
Sulfreen	Solid phase continuation of Claus reaction at a low temperature	Optimum performance requires $H_2S:SO_2$ ratio of 2:1	None; sulfur vapor condensation process utilized	Elemental liquid sulfur	Very low	Not appreciably removed	Capable of removing 80 to 85% of sulfur in the tail gas	No effect
Shell Copper Oxide	Thermal oxidation of sulfur compounds to SO_2, followed by adsorption by CuO; a concentrated SO_2 stream is produced by desorption with a reducing gas (H_2)	Incinerated Claus tail gas; no specific requirement on H_2S:SO_2 ratio	Copper oxide	Concentrated SO_2 stream	No data available	Oxidized by incineration	90% SO_2 removal	?
Wellman-Lord	Thermal oxidation of sulfur compounds to SO_2, followed by liquid absorption; concentrated SO_2 is produced and recycled to Claus plant	Incinerated Claus tail gas; process can handle SO_2 concentrations well over 10,000 ppm	Concentrated sodium sulfite, bisulfite solution	Concentrated SO_2 stream (up to 90% SO_2 content)	High	Oxidized by incineration, not removed by process	Can remove in excess of 95% of SO_2	No effect
SCOT	Sulfur species are catalytically reduced to H_2S; H_2S is scrubbed in a regenerable amine system	Applicable to Claus tail gas	Alkanolamine solution	Concentrated H_2S stream	Moderate	Catalytically reduced to H_2S	Can remove 97% of sulfur species	Reduces conversion efficiency by catalyst; high CO_2 levels reduce efficiency of alkanolamine system

to less than 500 ppmv. As with the Claus process, these processes can tolerate high concentrations of CO_2 in the feed gas. In the Beavon and SCOT processes, hydrogen or synthesis gas is used for the reduction of oxidized sulfur; the reduction is carried out over a cobalt-molybdate catalyst. In existing commercial applications, the tail gas from the Beavon and SCOT processes is treated for H_2S removal/sulfur recovery by the Stretford and alkanolamine processes, respectively. Total sulfur levels of less than 100 ppmv have been achieved by the application of Beavon-Stretford and SCOT-alkanolamine systems. In contrast to the first category of processes (processes which extend the Claus reaction), Beavon-Stretford and the SCOT-alkanolamine systems are adversely affected by high levels of CO_2 in the feed gas. The CO_2 in the feed gas reduces the efficiency of the catalytic reduction of COS and CS_2 and impairs the effectiveness of the Stretford and alkanolamine absorption systems. The third category of processes which involve incineration followed by SO_2 recovery have been applied to Claus plant tail gas and to utility boiler flue gases. These processes are capable of removing over 90% of the total sulfur in the feed gas. The Chiyoda Thoroughbred 101 and the Shell-CuO processes which employ sulfuric acid and CuO as sorbents, respectively, are not affected by high levels of CO_2 in the feed gas. In the Wellman-Lord process the sorbent is an alkaline solution of sodium sulfite/bisulfite whose capacity for SO_2 absorption may be affected by very high levels of CO_2 in the feed gas. (The use of the Wellman-Lord process for SO_2 removal has been successfully demonstrated on flue gases from coal-fired utility boilers which contain over 10%v CO_2).

5.2.3 SO_2 Control and/or Recovery

As indicated in Figure 5-2, SO_2-bearing gaseous streams which may require control are flue gases primarily originating from the incineration of gas streams containing reduced sulfur and from combustion related sources (e.g., char combustion, coal pretreatment, etc.). Of a wide variety of processes which have been proposed for removal of SO_2 from combustion gases, only a few have reached a commercial stage of development. Processes which may be considered commercially available at the present time are Wellman-Lord, Chiyoda Thoroughbred 101 and Shell copper oxide which were discussed in Section 5.2.2

and the lime/limestone slurry and the dual-alkali scrubbing processes which are discussed below. Data sheets for these processes are presented in Appendix D. A number of other scrubbing processes were reviewed in this program but eliminated from further consideration primarily due to the fact that they are not commercially developed, are not sufficiently reliable, and/or have relatively low SO_2 removal efficiencies. The nahcolite and the citrate processes, for example, have not been demonstrated on a commercial scale. The magnesium oxide scrubbing process which has been tested on a medium size utility boiler suffers from low on-line "availability." The fly ash slurry scrubbing which is proposed for low sulfur western coals has achieved sulfur removal efficiencies which only sometimes meet the New Source Performance Standards.

Table 5-5 presents the key features of the lime/limestone slurry and dual alkali scrubbing processes. Both processes have been developed and used for the removal of SO_2 from utility and industrial boiler flue gases. In the lime/limestone process, the flue gas is scrubbed with a lime or limestone slurry (6% - 12%) to remove the SO_2. Where used, initial scrubbing may be carried out in a venturi scrubber which is designed to remove most of the residual particulate matter. The bulk of the SO_2 removal is accomplished downstream in an absorption tower. The resulting spent calcium sulfite/sulfate sludge may be discharged to a thickener/settling pond with the clarified liquid returned to the process. Being a "throw-away" process, the process generates a relatively large volume of sludge which requires processing and/or disposal. In the proposed design for a $7x10^6$ Nm^3/day (250×10^6 SCF/day) WESCO gasification plant which uses coal for on-site steam and power generation and features flue gas desulfurization, the amount of sludge (dry weight basis) produced is estimated at 220 tonnes/day (263 tons/day) compared to 1280 tonnes/day (1410 tons/day) of gasifier ash and 227 tonnes/day (230 tons/day) ash from power generation(9). SO_2 removal efficiencies of up to 99% have been obtained in applications to flue gases from the combustion of high sulfur coals.

A concentrated sodium sulfite scrubbing solution is employed in the dual alkali process. The reaction of SO_2 with sodium sulfite produces sodium bisulfite which is reacted with lime in a separate vessel to regenerate

TABLE 5-5. KEY FEATURES OF LIME/LIMESTONE SLURRY AND DUAL ALKALI SCRUBBING PROCESSES

Process Feature	Lime/Limestone Slurry Scrubbing	Dual Alkali Scrubbing
Principle	Liquid phase absorption of SO_2 in a lime or limestone slurry.	Liquid phase absorption of SO_2 in a sodium hydroxide, sodium sulfite, sodium sulfate and sodium carbonate solution. A dilute mode process is used for SO_2 concentrations of 250 to 1500 ppm and a concentrated mode is used for SO_2 concentrations of 1800 to 8000 ppm and where less than 25% oxidation of collected SO_2 is encountered
Feed Stream Requirements	Particulates must be primarily removed in a venturi scrubber.	O_2 must be less than 7% for concentrated mode. Excessive particulates must be removed in a venturi scrubber.
Absorbent	6 to 12% lime or limestone slurry.	Sodium hydroxide, sodium sulfite, sodium sulfate and small amount of sodium carbonate.
Product	Calcium sulfite and calcium sulfate.	Primarily calcium sulfite and calcium sulfate.
Efficiency	Generally 70 to 90% for utility firing of high sulfur coal. 95-99% can be obtained. Removal efficiency will vary according to scrubber type and gas pressure drop. Over 99% removal efficiency can be achieved.	Capable of over 99% removal for typical coal fired utility flue gas and a concentrated mode process. A General Motors demonstration (dilute mode) and an FMC pilot plant (concentrated mode) operate at approximately 90% SO_2 removal.
Advantages	Low capital and O&M costs. SO_2 and particulates are removed. Fairly simple process. Conventional process equipment.	Low capital and O&M costs. SO_2 and particulates are removed. Conventional process equipment.
Disadvantages	On line reliability may be low (70 to 85%); in a typical power plant, produces ~2 times (dry weight basis) as much waste sludge as collected ash(38). For low sulfur coals, SO_2 removal efficiency should be as low as 50%.	In a typical power plant, produces ~1.5 times (dry weight basis) as much calcium sulfite/sulfate waste sludge as collected ash(38). Corrosion and pitting problems may require specific materials of construction.

sodium sulfite and precipitate calcium sulfite. The calcium sulfite sludge is concentrated by filtration prior to disposal. The dual alkali process can achieve 99% SO_2 removal efficiency when treating relatively concentrated SO_2 streams (e.g., 1800-8000 ppmv) and 90% SO_2 removal when treating more dilute SO_2 streams (e.g., 250-1500 ppmv). Like the lime/limestone slurry process, the dual alkali process generates large amounts of waste $CaSO_3/CaSO_4$ sludge (in a power plant application, typically about 1.5 times as much as the amount of ash generated in the plant(38)).

5.2.4 Incineration

Incineration (oxidation with air) is used to (a) convert the reduced sulfur species to SO_2 for direct discharge to the atmosphere or for subsequent SO_2 recovery, and/or (b) oxidize residual organics (gaseous and particulate) and carbon monoxide to carbon dioxide and water. When the product gas is to be discharged directly to the atmosphere, the incineration may consist of flaring, diversion of the gas to the industry/utility boiler, or combustion in a separate incinerator (afterburner) with or without the use of supplemental fuel. The latter type of incineration would also be used when the product gas is to be further treated for SO_2 removal. To achieve complete oxidation at a lower temperature, the separate incineration of the raw gas may be carried out over a catalyst bed (catalytic oxidation).

Depending on the incinerator design and the operating conditions, incineration can result in oxidation of over 90% of hydrocarbons, CO and reduced sulfur compounds. Incineration is generally a simple and reliable operation. However, in the presence of high sulfur loadings, some corrosion problems may occur. The use of supplemental fuels with feed gases containing low heating values can represent a significant operating cost.

5.2.5 CO, Hydrocarbon and Odor Control

The gaseous streams which may require hydrocarbon, CO and odor control are tail gases from sulfur recovery, vent gases from storage facilities, pretreatment off-gases, lockhopper vent gases, catalyst regeneration/decommissioning off-gases, and transient gases. Hydrocarbons, carbon monoxide and odor emissions can be controlled by incineration. Hydrocarbon emissions can also be controlled by gas processing using activated carbon adsorption. The use of thermal and catalytic incineration for emission control was discussed in Section 5.2.4.

Activated carbon adsorption is utilized for removal of hydrocarbons and other organics, particularly odor-producing compounds. Impurities are adsorbed on a solid bed of activated carbon by cohesion or chemical reaction. Spent carbon is regenerated by application of heat or chemical treatment. Efficiencies of up to 99% may be obtained depending upon the type of carbon used, the carbon loading and the nature of material to be adsorbed.

5.2.6 Particulate Control

As indicated in Figure 5-2, gaseous waste streams which may require treatment for particulate control include char combustion, incineration and transient gases; catalyst regeneration/decommissioning off-gases; lockhopper vent gases and pretreatment off-gases. The particulate control devices which may be applicable to these streams are cyclones, fabric filters (baghouses), venturi scrubbers* and electrostatic precipitators. The key features of these devices including the advantages and disadvantages of each are presented in Table 5-6. Although some of the equipment (e.g., cyclones and venturi scrubbers) will be used for the removal of particulates from process gases, the discussion in this section addresses only their application to waste gas treatment.

As indicated in Table 5-6, the four control devices considered vary in their operating principle, effectiveness in removing particles in different size fractions, temperature applicability, particulate loading limitation and energy requirements. Cyclones are generally employed for the removal of bulk particulates (generally greater than 5μ in size) and, in many cases, ahead of other control devices. The capital and operating costs for cyclones are relatively low. Baghouses have very high particulate removal efficiency, and can lend themselves to applications involving small or intermittent gas flows. Baghouses, however, have high pressure drops (e.g., in comparison to electrostatic precipitators) and cannot ordinarily handle wet gases, gases containing

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*Other types of wet scrubbers, which are commonly used for quenching and absorption/desorption of gases can effect some degree of particulate removal. Relative to venturi scrubbers, however, the particulate removal efficiencies of these devices are very low, specially for small size particles.

TABLE 5-6. KEY FEATURES OF PARTICULATE CONTROL EQUIPMENT

Control Device	Operating Principle	Efficiency Range, wt %	Particle Size Removal Range	Particulate Loading Limitation	Pressure Drop	Advantages	Disadvantages
Cyclone	Removal of particulates from a gas by imparting a centrifugal force to the gas stream. The inertia of the particulates carries them to the cylindrical walls where they fall to the bottom of the cyclone for removal.	50 to 80% for 5 µm 80 to 95% for 5 to 20 µm	>5 µm	>2.4 g/m^3 (>1 gr/ft^3)	1.3-10.2 cm (0.5 to 0.4 in.) W.G.	High reliability due to a simple collection system. Low energy requirements.	Cannot efficiently remove particulates below 5 µm
Fabric Filter (Baghouse)	Removal of particulates from a gas stream by impaction or interception on a fabric filter (generally tubular shape). Particulates can be removed from filter media by mechanical shaking or a pressurized reverse air flow.	98.5 to 99.5% for 0.25 to 0.5 µm 99.0 to 99.5% for 0.75 to 1.0 µm 99.9% for 100 µm	>0.2 µm	>0.24 g/m^3 (>0.1 gr/ft^3)	5.1-25 cm (2 to 10 in.) W.G.	High particulate collection efficiency.	High capital and operating costs. Plugging problems will result if feed stream is saturated or wet. Temperature limit varies with type of filter media utilized. Generally limited to 560°K (550°F) maximum temperature.
Venturi Scrubber	Removal of particulates from a gas stream by impingement with atomized scrubbent droplets. The agglomerated particles are subsequently removed in a centrifugal collector.	60 to 92.5% for 0.25 µm 85 to 97.2% for 0.5 µm 92 to 99% for 0.75 µm 95 to 99.6% for 1.0 µm	>0.5 µm	>0.24 g/m^3 (>0.1 gr/ft^3)	25-250 cm (10 to 100 in.) W.G.	High particulate collection efficiency capable of treating streams with wide temperature, pressure and gas composition ranges.	Liquid scrubbing wastes are producted which may require treatment. High efficiencies require high energy consumption. Some potentially valuable dry material cannot be directly recovered.
Electrostatic Precipitator	Removal of particulates from a gas stream by imposing an electrical charge and collecting the charged particles on oppositely charged collector plates. Collected solids are normally removed by mechanical rapping with hammers or vibrators.	90 to 99.4% for 0.1 µm 90 to 98.7% for 0.5 µm 95 to 99.6% for 1.0 µm 98 to 99.9% for 5.0 µm	>0.1 µm	>0.24 g/m^3 (>0.1 gr/ft^3)	0.51-2.5 cm (0.2 to 1 in.) W.G.	Suitable for high temperature applications. Low pressure drop, can treat large volumes of gas. Highly efficient for small particulates.	High capital costs. Generally applied at pressures near atmospheric. Collected particulate must have a suitable electrical resistivity to facilitate efficient collection. Not applicable to explosive gases.

oily materials or gases having temperatures in excess of 560°K (550°F). Venturi scrubbers can generally handle gases having temperatures higher than those which can be handled by fabric filters, can operate at high pressures, can tolerate wet and tarry gases, and can be very efficient for the removal of submicron particles. High removal efficiencies, however, have an associated high energy penalty. In contrast to other devices in which the particulates are collected in dry form, venturi scrubbers generate a scrubbing liquid blowdown and hence a wet sludge which is more voluminous and generally more difficult to dispose of. When hot gases are to be handled, use of venturi scrubbers would result in gas cooling and the addition of moisture to the product gas. This would represent an energy penalty if the gas is to be subsequently incinerated (e.g., for CO and hydrocarbon control or used as fuel). Electrostatic precipitators are high efficiency particulate removal devices, have low pressure drops, are capable of handling large volumes of gases and can tolerate high feed gas temperatures. Electrostatic precipitators, however, are not economical for treating small or intermittent gas flows and have not been applied commercially to gases above atmospheric pressure.

5.2.7 Gas Compression and Recycling

Three of the gas streams shown in Figure 5-2 can potentially be recycled to various streams in the gasification plant for material/energy recovery and pollution control. These streams are: (1) feed lockhopper vent gases, (2) pretreatment off-gases, and (3) depressurization, stripping and vent gases. If raw product gas is used for pressurization of the feed lockhopper, the feed lockhopper vent gases can be compressed and added to the raw product gas or reused for lockhopper pressurization. Alternatively, this gas may be used as plant fuel. If the concentrated CO_2 stream from acid gas treatment is used for lockhopper pressurization, the vent gases may be compressed for reuse or recycling to the acid gas treatment system. The pretreatment off-gases may be compressed and added to raw or quenched product gas or injected into the gasifier. Depressurization, stripping and vent gases may be compressed and added to the raw or quenched product gas. The vent gases which generally contain little or no sulfur compounds may also be directly used as fuel.

Because of the relatively small volumes of the waste gases generated at the pilot gasification facilities in the U.S., and because most of these pilot plant operations have been aimed primarily at the development of gasification technology, the above-listed compression and recycling options have not been tested at the U.S. facilities. These options have also not been employed at commercial gasification facilities abroad because of cost considerations and the less stringent emission restrictions. At these facilities the waste gases are generally disposed of by flaring or direct discharge to the atmosphere.

5.2.8 NO_x Control

The flue gases generated in the combustion of char and waste gases will contain varying amounts of NO_x depending on the fuel type and combustion conditions. Control of NO_x emissions can be achieved through combustion modification and/or by use of add-on processes. Combustion modification which may include staged-combustion, use of low excess air, reduction of air preheating, steam or water injection and reduced heat release rate may result in as much as 60% reduction in NO_x emissions. Somewhat lower efficiencies are obtained when the fuel (e.g., coal and char) contains nitrogen. Add-on processes generally fall into two categories: dry processes and wet processes. Most dry processes involve catalytic reduction of NO_x with ammonia which is added to the flue gas. Wet processes involve a combination of absorption and oxidation or reduction for NO_x removal. Removal efficiencies greater than 90% can be obtained with dry or wet processes.

Only a few of the add-on NO_x control processes have been developed commercially. Applications of the few processes which have attained commercial status have been limited to facilities in Japan and to oil-fired utility and industrial boilers. Except in connection with on-site steam and power generation and/or in those gasification processes which incorporate external char combustion, NO_x control would not be a major concern in a commercial high Btu gasification facility.

5.3 AIR POLLUTION CONTROL IN INTEGRATED FACILITIES

This section discusses the alternative approaches to control of air pollution emissions in integrated coal gasification facilities. The discussion does not include emission controls from conventional sources associated with coal preparation (crushing, screening, drying) and coal combustion for steam and power generation. Based on the relative volumes and characteristics of various waste gases generated in a gasification plant and the relative magnitude of the environmental impacts associated with potential emissions of "criteria" and other pollutants contained in such gases, sulfur-bearing waste gases would appear to be of primary concern for emission control. Depending on the specific gasification process and plant design, control of hydrocarbons, carbon monoxide and odor may also be important. Control of particulates and NO_x would generally be of less importance in a gasification plant since process-related large volume gaseous wastes generally do not contain high levels of these constituents. Processes such as Cogas, CO_2-Acceptor and Synthane which employ external char combustion, however, generate a relatively large volume of flue gas which contains high levels of particulates and, like all other combustion gases, some NO_x.

5.3.1 Control of Sulfur Emissions

The sulfur-bearing streams in a high Btu gasification plant would fall into two general categories, those containing reduced sulfur compounds (primarily H_2S) and those containing oxidized sulfur compounds (primarily SO_2). The first category consists of concentrated acid gases, depressurization and stripping gases, lockhopper vent gases, and pretreatment off-gases. The second category consists of char combustion and incineration gases and catalyst regeneration/decommissioning off-gases. In terms of total volume and concentration, the concentrated acid gases and the char combustion and incineration gases are by far the most important.

Table 5-7 presents a number of options available for the management of the sulfur-bearing gas streams and highlights some major advantages and disadvantages of each option. Some options (e.g., incineration of concentrated acid gases and atmospheric discharge) would be technically unattractive and environmentally unacceptable for use in the U.S. The applicability of certain options (e.g., those using Claus, Stretford or G-V processes for sulfur recovery) is dependent on the sulfur concentration in the gas stream which is in turn determined by the sulfur content of the feed coal, the specific gasification processes used and the acid gas treatment processes employed. Accordingly, the selection of the best option for the management of a specific sulfur-bearing stream should be based on a case-by-case analysis. This is also

TABLE 5-7. OPTIONS FOR THE MANAGEMENT OF SULFUR-BEARING WASTE GASES IN INTEGRATED FACILITIES

Waste Gas	Control Options*	Comments
Concentrated Acid Gases	1. Claus plant sulfur recovery	1. Probably unacceptable because of high concentration of total sulfur in the tail gas; only applicable to streams containing more than 15% H_2S.
	2. Claus plant sulfur recovery and tail gas incineration	2. Probably unacceptable because of high levels of SO_2 in the tail gas; only applicable to streams containing more than 15% H_2S.
	3. Claus plant sulfur recovery and tail gas treatment	3. Tail gas treatment not highly effective when feed gases contain high levels of CO_2; only applicable to streams containing more than 15% H_2S.
	4. Same as 1 plus SO_2 control and/or recovery	4. Reasonable option when feed gases contain more than 15% H_2S; total sulfur removal efficiency may be less than option 5.
	5. Stretford or G-V sulfur recovery	5. Inapplicable to waste gases containing high levels of H_2S; may not be economical for gases containing high CO_2 levels; discharge may contain high COS and HC levels.
	6. Same as 5 plus tail gas treatment	6. Same as for Option 5.
	7. Same as 6 plus incineration	7. Same as for Option 5 except for oxidation of CO and HC compounds
	8. Incineration	8. Unacceptable because of high SO_2 emissions.
	9. Same as 8 plus SO_2 control and/or recovery	9. Many SO_2 recovery processes generate sludges requiring disposal;no by-product sulfur is recovered; regenerable SO_2 removal processes must be operated in conjunction with sulfur recovery units.
	10. Incineration, treatment for control and/or recovery in combination with flue gases from utility boilers or char combustion	10. Same as for Option 9; some economy of scale may be realized if flue gas desulfurization is required on utility boilers.
Depressurization and Stripping Gases	1. Combining with concentrated acid gas streams and use of any of the treatment options listed above	1. See individual options above; may have considerable dilution effect on the concentrated acid gas streams.
	2. Compression and addition to product gas stream	2. Permits material recovery; some energy input required for compression.
	3. Use as fuel	3. Stripping gases may have limited fuel value; may have high SO_2 emissions.
	4. Incineration	4. High levels of SO_2 emissions.
	5. Same as 4 plus SO_2 control and/or recovery	5. See comments for Options 9 and 10 for Concentrated Acid Gases.
Pretreatment Off-Gases	1. Combining with product gas	1. Product gas dilution and energy requirement for compression; permits material and energy recovery.
	2. Injection into gasifier	2. Permits material and energy recovery; will require gasifier design modification and energy input for compression.
	3. Use as fuel	3. May have high SO_2 emissions.
	4. Incineration	4. See comment for Option 4, Depressurization and Stripping Gases.
	5. Same as 4 plus SO_2 control and/or recovery	5. See comment for Option 5, Depressurization and Stripping Gases.
Lockhopper Vent Gases	1. Compression and recycling	1. See comment for Option 2, Pretreatment Off-Gases.
	2. Incineration	2. See comment for Option 4, Depressurization and Stripping Gases
	3. Same as 2 plus SO_2 control and/or recovery	3. See comments for Options 9 and 10, Concentrated Acid Gases.
	4. Use as fuel	4. See comment for Option 3, Depressurization and Stripping Gases.
Catalyst Regeneration/ Decommissioning Off-Gases	1. Incineration	1. See comment for Option 4, Depressurization and Stripping Gases.
	2. Same as 1 plus SO_2 control and/or recovery	2. See comments for Options 9 and 10, Concentrated Acid Gases.
Char Combustion, Incineration and Treatment Gases	1. Incineration (for transient gases)	1. See comment for Option 4, Depressurization and Stripping Gases.
	2. Same as 1 plus SO_2 control and/or recovery	2. See comments for Options 9 and 10, Concentrated Acid Gases.

*Except where gas compression and recycling is used, all options culminate in discharge of the treated gas to the atmosphere complicated by the lack of data on (1) the detailed composition of gas streams from applicable facilities and (2) performance, costs and environmental aspects of actual application of control processes to coal gasification gas streams. For example, the Stretford process has been demonstrated to be highly effective for H_2S removal for refinery and coke oven gases which contain low to moderate levels of CO_2; however, insufficient data exist for commercial applications to coal gasification acid gases which in some cases may contain 90% or more CO_2. (A small Stretford unit is being tested at the Fort Lewis SRC pilot plant handling concentrated acid gases from a DEA unit. Satisfactory performance of the unit has not been achieved to date(39).) For the G-V process, which is capable of handling acid gases containing high levels of CO_2 and uses an arsenic-based sorbent, the hazardous characteristics are not known for commercial applications.

Some of the options listed in Table 5-7 have not appeared in the designs for proposed commercial high Btu gasification facilities. Most possibly this is due to the lack of engineering data for such options. For example, all conceptual designs include Claus or Stretford processes for the recovery of H_2S from concentrated acid gases. Due to some of the shortcomings associated with these processes for handling gases containing high levels of CO_2, it is possible that gas incineration followed by SO_2 recovery (in a Wellman-Lord or wet limestone unit) alone or in conjunction with flue gas from utility boilers may be technically and economically superior.

5.3.2 Control of Particulate Emissions

In an integrated gasification facility which employs processes such as Lurgi which do not generate chars requiring combustion/gasification in an external vessel, the particulate emissions directly associated with the main gasification operation, gas purification and gas upgrading operations are generally very small when compared to emissions from other areas such as coal preparation and on-site coal combustion for power generation and process heating. In integrated facilities employing processes such as Cogas, CO_2-Acceptor and Synthane which incorporate char gasification/combustion external to the main gasifier, the combustion flue gas from the burning of char and/or supplemental fuel will also be the major source of particulate emissions. When combustion of char and/or coal is carried out in a conventional boiler, control devices such as electrostatic precipitators and fabric filters which are widely used in the utility industry would be applicable. In processes such as CO_2-Acceptor which combust/gasify char under pressure, a combination of cyclone and venturi scrubbers would probably be most applicable. The removal of particulates from such flue gases would probably be required for protection of downstream gas turbines used to recover energy from the flue gas whether or not emission control would be necessary.

Process-related potential sources of particulate emissions in an integrated gasification facility which are less important (if equipment is properly working and operating) than char gasification/combustion flue gases are pretreatment off-gases, lockhopper vent gases and catalyst regeneration/decommissioning off-gases. The possible options involving compression and recycling of the pretreatment off-gases and lockhopper vent gases were discussed in Section 5.3.1. When these gases are not recycled, the most suitable device for the control of particulate emissions from these two sources would be the venturi scrubber. Fabric filters would generally be inapplicable to these gases, which normally contain tarry materials and high moisture levels. Fabric filters, however, would probably be applicable to the catalyst regeneration/decommissioning off-gases since these gases would normally contain low levels of moisture, are generally devoid of tarry materials, and are generated intermittently and in small volumes.

5.3.3 Control of Carbon Monoxide, Hydrocarbons and Odorous Emissions

No large sources of hydrocarbons and carbon monoxide emissions are expected in a commercial coal gasification facility. The sources and magnitudes of these emissions would generally depend upon the gasification process used, and the gas purification and upgrading operations employed. When the CO_2-Acceptor process is used for coal gasification, emissions of non-methane hydrocarbons are very low since no hydrocarbons other than methane are produced in the gasifier. Some carbon monoxide emissions, however, may be associated with this process as a result of fluidized bed combustion of the char which has to be carried out with very low excess air. The Hygas process would have several potential sources of hydrocarbon emissions due to the use of coal-derived oil for slurry feeding and the net production of such oil in the process. For coals requiring pretreatment, the Hygas process also will generate a hydrocarbon- and CO-bearing off-gas. The level of hydrocarbons in the concentrated acid gas stream produced in product gas purification operations depends on the specific gas treatment process employed. For example, when handling feed gases containing nonmethane hydrocarbons, concentrated acid gases produced by "physical solvent" processes, such as Rectisol, will also contain some nonmethane hydrocarbons, thus requiring hydrocarbon control in conjunction with or subsequent to sulfur recovery. On the other hand, processes such as Benfield and Catacarb will produce a concentrated acid gas stream which is essentially devoid of all hydrocarbons, thus eliminating the hydrocarbon control requirements. Options for the control of hydrocarbons and CO are essentially limited to control at the source (e.g., recycling of the pretreatment off-gases or combustion modifications), use of incineration and, in the case of hydrocarbons, use of activated carbon adsorption. Flaring of process and waste gases would most likely be employed at all commercial gasification facilities for the control of hydrocarbons, CO, odors, H_2S, etc. during transient operations. Although at the existing gasification pilot plants the product gas and waste gases are disposed of by flaring (even during steady state operation), little data are available on the effectiveness of these flaring operations. At commercial facilities flaring of the waste gases would be of intermittent nature. The composition of the flare off-gas would be highly variable, depending primarily on the nature and volume of the gases being flared.

Production of odorous compounds (e.g., H_2S, mercaptans and heterocyclic aromatics such as pyridine and thiophene) would be associated with the operation of almost all gasification plants. Their release to the atmosphere, even in very small quantities, can present significant odor problems. As with the hydrocarbon emissions, options for the control of odor are limited to source control, incineration and carbon adsorption. Since in an integrated facility, fugitive emissions (e.g., from spills and leaks) and emissions from non-process sources (e.g., cooling towers and wastewater treatment units) can contribute significantly to the total odor emissions, good housekeeping practices, proper operating procedures and routine maintenance are essential to minimize the odor problem.

5.3.4 Control of Non-Criteria Pollutant Emissions

In addition to the criteria pollutant (SO_2, particulates, hydrocarbons, CO and NO_x) and H_2S, gaseous waste streams in an integrated gasification facility may contain a number of other constituents which even though present in relatively small concentrations may be of environmental concern due to their hazardous characteristics. These pollutants fall into two general categories: trace elements (and their compounds) and trace organics. Trace elements such as Hg, As, Sb, F, Cd, B, Se, and Be which are originally present in the coal are volatilized to varying degrees during coal pretreatment and gasification (see Section 2.4.3). Trace elements may also be present in the gas stream in the form of particulate matter. Some of the trace elements contained in the raw product gas are removed during subsequent gas processing (e.g., quench and dust removal); others may become components of the waste gases produced in gas purification and upgrading and lockhopper operations. In processes which employ char combustion/gasification, the resulting flue gases would also contain trace elements (in particulate and gaseous forms). In addition to coal as a source of trace element emissions, the off-gases from the regeneration and decommissioning of methanation catalysts can be a source of trace element emissions. These emissions are usually in the form of particulate nickel or nickel carbonyl.

As discussed previously, some high Btu gasification processes (e.g., Lurgi and Hygas) produce significant quantities of tars and/or oils containing a range of organics, some of which may be hazardous because of toxicity, carcinogenicity, teratogenicity, etc. Examples of classes of such hazardous organics are polynuclear aromatic hydrocarbons (e.g., cholanthrenes and benzopyrenes), heterocyclic aromatics (e.g., thiophenes, pyridines and dibenzocarbozoles) and polyhydric phenols. The more volatile of these compounds (e.g., pyridines and thiophenes) may become components of the concentrated acid gases; depressurization, stripping and vent gases; lockhopper vent gases and pretreatment off-gases. The less volatile compounds would tend to become components of the aqueous and organic condensates and may be present in certain gas streams (e.g., pretreatment off-gases) in the particulate form.

Many of the processes and devices used for the control of criteria pollutants are also effective to varying degrees in removing trace elements and organics from gaseous waste streams. For example, particulate trace elements and organics are largely removed by particulate control devices. When venturi scrubbers are used for particulate control, the cooling of the gas also results in the condensation and removal of some of the volatile components. Under proper operating conditions, incineration of waste gases can bring about nearly complete destruction of trace organics. Some of the highly volatile substances such as mercury, arsine and nickel carbonyl may not be totally removed by some of the conventional controls such as incineration and venturi scrubbing. At the present time, adequate technical data are not available to estimate the levels of these substances in various waste gases in an integrated gasification facility and the effectiveness of the existing controls for their removal. Furthermore, inadequate environmental and toxicological data prevent estimation of acceptable emission levels for many of these substances.

5.4 DATA GAPS AND LIMITATIONS

The data gaps and limitations relate primarily to the composition of the waste gases which would require processing for air pollution control in a commercial gasification facility, the toxicological properties of trace constituents and the ecological implications of various substances in gaseous emissions, the applicability and cost of various control technologies and waste management options, energy use and water and solid waste pollution control requirements. The limited data available on waste gases are from pilot plant operation in the United States, a few tests of American coals in the Westfield Lurgi plant and the operation of other foreign commercial facilities. The limitations of the available data on operation at foreign gasification sites were discussed in Section 3.4.

As was discussed in Sections 2.5 and 3.4, the pilot plant operations in the U.S. have been primarily aimed at the development of the gasification technology. These pilot plants do not incorporate all the peripheral operations which would be employed in an integrated facility and which would constitute additional sources of discharges in such a facility. For example, the Synthane pilot plant does not incorporate char gasification/combustion which would be employed in a commercial facility. The gasifiers and the limited peripheral units which are being tested in the pilot plant programs do not necessarily represent full-scale units because of anticipated scale-up design changes and equipment/process modification and substitution. At the CO_2-Acceptor pilot plant, for example, the regenerator flue gas has been scrubbed with a sodium hydroxide solution for SO_2-removal and all reported gas composition data have been obtained on the scrubbed gas. In a large-scale facility, flue gas desulfurization would most likely employ one of the commercially developed processes which uses reagents other than sodium hydroxide. Essentially no composition data are available for some of the gas streams (e.g., the lockhopper vent gases). The composition data which have been reported for some of the gaseous wastes are not very comprehensive and in general do not address environmentally important trace constituents. For example, quantitative data are not available on trace elements and trace organic sulfur and nitrogen compounds for all gas streams. Information is lacking on the toxicological, ecological and synergistic properties of most trace substances present in gaseous emissions. Very little information is available on the transportability, atmospheric residence time and ultimate fates of such constituents. For these reasons and the fact that accurate engineering estimates have not been made of the levels of many environmentally important constituents in gasification plant emissions, the anticipated ambient levels of such constituents cannot be predicted at this time.

Nearly all the engineering and cost data which are available for air pollution control processes and devices are for applications to waste and process gases in industries other than coal gasification. Moreover, the energy requirements and the liquid and solid wastes generated by air pollution control processes/devices in applications to coal gasification gases are not accurately known and hence the impact that the use of such technologies would have on overall facility energy requirements and pollution control are not well defined. In some cases where control technology developers/licensors might have generated data on applicability of a control technology to coal gasification gases and on the costs, energy requirements and waste generation characteristics associated with such applications, such data are generally considered proprietary and hence not publicly available. Because of (a) the lack of detailed composition data for coal gasification waste gases, (b) known differences between coal gasification waste gases and process/waste gases in other industries, and (c) very limited testing of the control processes/devices on coal gasification waste gases, there is a very limited technical data base to establish applicability of the existing control technologies to coal gasification waste gases. Such data would also be needed to determine necessary process/equipment modifications, to conduct comparative evaluation of various air pollution control options for commercial facilities, and to estimate costs associated with the control technologies and options. Because of the data limitations mentioned above, accurate estimation of the magnitude of emissions from commercial high Btu gasification facilities and the environmental impacts associated with such emissions cannot be made at this time.

5.5 RELATED PROGRAMS

Many of the programs discussed in Sections 2.6, 3.4, 4.1.3 and 4.2.3 are expected to generate some data on the characteristics of waste gases from integrated facilities. Under an EPA contract, Cameron Engineers (Denver, Colorado) is preparing an outline and an example section for a "Multimedia Environmental Control Engineering Handbook" (MECEH). MECEH will include a detailed description of environmental control technologies applicable to coal conversion and will provide information on commercially available pollution control equipment. The objectives of the handbook are to: (a) categorize all commercially available control technologies into a systematic format, which can be easily assessed; (b) provide technical data for each process, including process descriptions, ranges of applications, efficiencies, and capital and operating costs; and (c) provide a list of those who supply the specific equipment and/or license the technology. C. F. Braun and Company (Alhambra, CA) is the "Evaluation Contractor" for a joint DOE-AGA coal gasification program. The company has been conducting a number of engineering studies, some of which relate to the management of sulfur emissions in commercial gasification facilities. As part of these studies, engineering and cost data have been and are being solicited for various process vendors. EPA has recently published guidelines on control of emissions from Lurgi coal gasification plants(37).

6.0 WATER POLLUTION CONTROL

Several process and air and solid waste pollution control modules in an integrated SNG facility would generate aqueous wastes requiring treatment. This section is a summary of the available information about the sources and characteristics of these wastewaters and the treatment processes/equipment which have been or could be used for the treatment of such wastewaters. Only those aqueous wastes which are specific to high Btu gasification and related operations are considered. Thus, wastewaters associated with coal storage (e.g., coal pile runoff) and preparation, raw water treatment, on-site steam and power generation and sanitary facilities are not addressed. (Some of these have been addressed in "Environmental Assessment Data Base for Low- and Medium-Btu Gasification", EPA 60017-77-125a and b, November 1977.) Detailed information on the individual wastewater treatment processes reviewed are presented in the "data sheets" contained in Appendix E.

6.1 SOURCES AND CHARACTERISTICS OF AQUEOUS WASTES

Figure 6-1 identifies the major sources and types of aqueous wastes in an integrated coal gasification facility. As indicated in this figure, seven general types of aqueous wastes may be produced in a gasification plant. These are; (1) particulate scrubber waters, (2) raw gas quench waters, (3) ash quench waters, (4) waste sorbents and reagents, (5) shift condensate, (6) methanation condensate, and (7) miscellaneous wastewaters (e.g., blowdowns, storm runoff from plant areas, accidental discharges, etc.). Not all of these aqueous wastes may be generated in all gasification plants. Table 6-1 identifies waste stream categories associated with each of the eight high Btu gasification processes evaluated. The composition of wastewater varies from plant to plant, depending on the process used, coal feed, operating conditions, water conservation and reuse practices incorporated in the plant design and "housekeeping" procedures. Most of the available wastewater composition data are for pilot plants which, although very useful, may not be entirely representative of

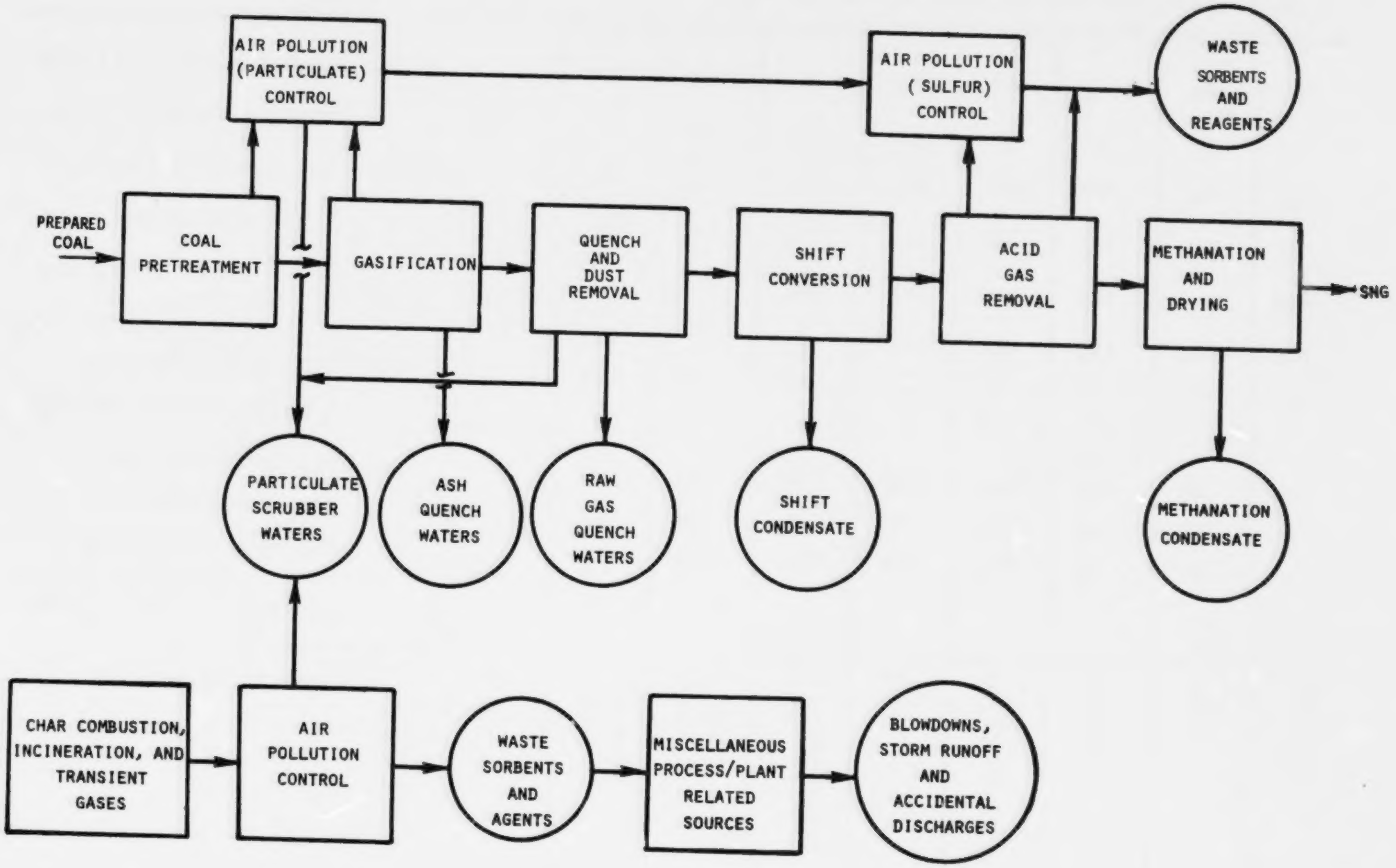
PREPARED COAL
COAL PRETREATMENT
AIR POLLUTION (PARTICULATE) CONTROL
GASIFICATION
QUENCH AND DUST REMOVAL
SHIFT CONVERSION
ACID GAS REMOVAL
AIR POLLUTION (SULFUR) CONTROL
WASTE SORBENTS AND REAGENTS
METHANATION AND DRYING
SNG
PARTICULATE SCRUBBER WATERS
ASH QUENCH WATERS
RAW GAS QUENCH WATERS
SHIFT CONDENSATE
METHANATION CONDENSATE
CHAR COMBUSTION, INCINERATION, AND TRANSIENT GASES
AIR POLLUTION CONTROL
WASTE SORBENTS AND AGENTS
MISCELLANEOUS PROCESS/PLANT RELATED SOURCES
BLOWDOWNS, STORM RUNOFF AND ACCIDENTAL DISCHARGES

Figure 6-1. Major Process Modules Generating Aqueous Wastes in a Typical High Btu Gasification Plant

TABLE 6-1. AQUEOUS WASTE STREAMS ASSOCIATED WITH DIFFERENT HIGH BTU GASIFICATION PROCESSES

	Gasification Process							
Wastewater Category	Lurgi (dry ash)	Lurgi (slagging)	Hygas (steam-oxygen)	Cogas	CO_2-Acceptro	Synthane	Bigas	Hydrane
Particulate scrubber waters from treatment of:								
Pretreater Flue Gas	Yes	Yes	Yes	No	Yes	No	No	*
Lockhopper Vent Gas	Yes	Yes	No	No	Yes	Yes	No	*
Char Combustion Flue Gas	No	No	No	Yes	Yes	Yes	No	No
Raw Gas Quench Waters								
Cyclone Slurry	No	No	Yes	*	No	No	No	*
Quench Blowdown	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Ash Quench Water	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Shift Condensate	Yes	Yes	Yes†	Yes†	No	Yes	Yes	No
Methanation Condensate	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Waste Sorbents & Reagents	‡	‡	‡	‡	‡	‡	‡	‡
Miscellaneous Wastewaters	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

*Not known at this time; process not sufficiently developed or information not publicly available
†Depending on feed coal and operating conditions, shift may or may not be required
‡Depends upon specific acid gas treatment and pollution control processes employed.

commercial scale operations. Furthermore, since in most pilot plant operations, only the coal gasification has been emphasized, data are not available for all the waste streams listed in Table 6-1. For some streams where data are available, the data are not generally comprehensive in that not all environmental properties of interest have been addressed. Composite values or ranges of values reported for various parameters and constituents in wastewaters from selected gasification processes are presented in Table 6-2. The data in this table (and the "normalized" constituent/parameter production rates presented in Table 2-6) are based upon the information in Appendix A. A discussion of the available data by wastewater category follows.

6.1.1 Particulate Scrubber Waters

Depending on the gasification process used, the most likely sources of particulate scrubber waters are: pretreatment, lockhopper operation and char combustion. Coal pretreatment scrubber waters generally contain high levels of suspended and dissolved solids, and moderate levels of organics, as reflected by the TOC, phenol and oil and grease values shown in Table 6-2. The relatively high level of thiocyanate and the low levels of sulfide and cyanide can be attributed to the reaction between sulfide and cyanide under mildly oxidizing conditions. As discussed in Section 5.3.4, some of the more volatile of the trace elements in coal may be removed by scrubbing and thus become components of the scrubber water. If lockhopper vent gases are scrubbed in a venturi scrubber, the resulting scrubber water would be expected to contain high levels of suspended solids. When raw or quenched product gas is used for feed lockhopper pressurization, the scrubber water may also contain organics, ammonia, sulfide and thiocyanate. In gasification processes such as Synthane, CO_2-Acceptor and Cogas where the char is combusted/gasified, the scrubbing of the resulting flue gas will generate a scrubber water containing high levels of dissolved and suspended solids. As noted in Table 6-2, the reported scrubber water production rates vary from 6 to 8.5 ℓ/kg of coal, based on the pilot plant operation.

6.1.2 Raw Gas Quench Waters

In gasification facilities which use fluidized or entrained bed gasification (e.g., CO_2-Acceptor, Hygas, Cogas and Bigas) the scrubber water from

TABLE 6-2. SUMMARY OF THE REPORTED CHARACTERISTICS OF WASTEWATERS FROM HIGH BTU GASIFICATION PROCESSES (EXCEPT FOR pH AND AS OTHERWISE NOTED, ALL VALUES ARE IN MG/l)

Wastewater Categories	Production Rate l/kg (gal/lb) Coal	TSS	TOC	COD	Phenols	NH_3	$S^=$	CN^-	SCN^-	TDS*	Oil & Grease	pH
Particulate Scrubber Waters												
Pretreatment Flue Gas	7.9-8.5 (0.97-1.04)	700-1060	870-1200	-	1330	23-26	2-3	0.003-0.024	209-316	2600-4850	159-239	6.1-6.2
Lockhopper Vent Gas‡	-	-	-	-	-	-	-	-	-	-	-	-
Char Combustion Flue Gas	6 (0.75)	150-1630	-	5-70	<0.004	33-292	<0.01-3.2	<0.02	-	912-1300	<0.004	6.6-8.0
Raw Gas Quench Waters												
Quench Blowdown	0.031-4.4 (0.004-0.56)	23-15800	863-10000†	100-43000†	0.001-6600†	665-17800	0.01-1030	<0.001-14	6-360	426-4000	34-5000	7.2-9.8
Cyclone Slurries	1.4-4.1 (0.18-0.5)	13100-26000	490-1518	-	189-2455	67-439	34-99	<0.004-1.0	34-198	432-669	190-2190	7.1-8.0
Ash Quench Waters	2.9-6.1 (0.36-0.75)	4700-68000	78-243	135-290	<0.004-7.3	3.7-200	<0.01-230	<0.001-0.019	1.5-6.8	54-6244	8-50	7.4-12.3
Shift Condensate§	?	Low	?	Moderate	?	Low	Moderate/low	Very low	Low	Low	Low	?
Methanation Condensate§	-0.18 (0.022)‡‡	Very low	Very low	Very low	Very low	Very low	Very low	Very low	Very low	Very low	Very Low	Neutral

*Heavily dependent upon TDS levels in make-up water.

†Low values represent CO_2-Acceptor process, which generates essentially no non-methane hydrocarbons in the gasifier.

‡No actual data available; scrubber water composition would depend upon the composition of gas used to pressurize lockhoppers.

§Estimated; no actual operating data available for shift and methanation condensate.

‡‡Calculated based on 1 mole H_2O produced per mole of product methane.

gas quenching can be one of the most particulate-laden wastewater streams in the gasification complex. As noted in Table 6-2, TSS values of over 15,000 mg/ℓ have been reported for the Hygas quench water. In fixed bed processes such as Lurgi, the particulate loading in the raw product gas is generally lower and this is reflected in the lower suspended solids concentrations in the quench and organic condensates. The data in Table 6-2 indicate that the raw gas quench waters contain high levels of ammonia, sulfide and thiocyanate and are relatively low in cyanide. The low level of cyanide has been attributed to its reaction with sulfide to produce thiocyanate. The quench waters from processes such as Lurgi, Synthane and Hygas which produce tars and/or oils also contain high levels of organics (e.g., up to 6,600 mg/l of phenols and up to 10,000 mg/l of TOC). These quench waters also contain varying concentrations of trace organics such as carbazoles, benzofurans and benzopyrenes which can be hazardous. In addition to trace organics, the quench waters can also contain significant levels of certain trace elements originally present in the coal. Table 6-3 presents the trace element concentrations in Synthane and Hygas quench waters and on the percentages of the trace elements originally present in the coal which are found in the aqueous condensate from the Lurgi facility at SASOL, South Africa. As noted in the table, for the Lurgi facility, close to 90% of the arsenic, 42% of the fluoride, 35% of the cadmium and 32% of the mercury are present in the raw product gas quench water. The quench waters are usually slightly alkaline (due to the high ammonia levels) and the amount produced depends upon the gasification process and the design of the quench system.

Somewhat related to the gas quench water is the slurry water used to transport particulates collected by cyclones. Cyclones are employed in processes such as Hygas ahead of the quench system for bulk particulate removal. This stream can contain a very high concentration of particulates (reported values of up to 26,000 mg/ℓ) and somewhat lower levels of other constituents found in the raw product gas.

6.1.3 Ash Quench Waters

All gasification processes reviewed use water for ash quenching and transport. The ash quench waters are characteristically high in both suspended and dissolved solids and can have a very high pH (especially when high

TABLE 6-3. TRACE ELEMENTS REPORTED IN PRODUCT GAS QUENCH WATERS

Element	mg/l Concentration		% of Element Originally Present in Coal
	Synthane PDU (mg/l)	Hygas Pilot Plant (mg/l)	Lurgi (at Sasol)
Hg	0.027	-	32
As	0.001	-	90
Zn	0.13	37-63	-
Mn	0.2	40-206	36
Cr	0.043	<24	-
F	39	-	42
B	43	251-12000	3.5
Be	-	<2	1.6
Cd	-	<20	35
Pb	-	<60	3.2
V	-	<200	0.06
Sb	-	-	36

sodium lignites are gasified). The concentrations of ammonia, sulfides and organics are generally low in these waters. Although little quantitative data are available on the trace element composition of the ash quench waters, because of the high pH environment these waters are expected to contain low levels of most heavy metals (e.g., Zn, Cd, Pb, Cr, V) in dissolved form. Certain trace elements such as boron, selenium, arsenic and fluorine, which can exist as anions under alkaline conditions, may be present in significant quantities in these waters.

6.1.4 Shift Condensate

As discussed in Section 4.1.2, the cooling of the product gas after shift conversion results in the condensation of moisture. No actual analytical data are available on the composition of this condensate. Since shifting follows quench and dust removal, the condensate stream is expected to be relatively "clean", containing only small amounts of ammonia, sulfide and low molecular weight organics as major pollutants.

6.1.5 Methanation Condensate

As noted in Section 4.2.2, methanation is the final step in the production of SNG and is preceded by trace sulfur and heavy hydrocarbons removal steps. Accordingly, the methanation condensate is expected to contain very low levels of sulfur- and nitrogen-containing compounds and nonmethane organics. One mole of water is produced per mole of methane produced. No actual composition data have been reported for the methanation condensate.

6.1.6 Waste Sorbents and Reagents

Waste sorbents and reagents include routine solvent or solution blowdowns from acid gas treatment and air pollution control and wastes resulting from these systems in cases of upsets and transient conditions. Continuous or periodic discharges of blowdowns from these systems are necessary to avoid contaminant build-up and maintain sorbent activity. The nature of these wastewaters and the quantities discharged would depend on the specific process used and its design, the characteristics of the gas treated and the frequency and nature of the upsets and transient conditions. Since no commercial SNG facilities currently exist, data are not available on the characteristics of waste sorbents from acid gas treatment and air pollution control in such applications. The conceptual design of the proposed El Paso Natural Gas Company Burnham SNG facility assumes a solution blowdown rate of 24.7 $kg/10^6 Nm^3$ (1.46 $lb/10^6$ scf) of treated gas for the Stretford unit handling a concentrated CO_2 gas stream from the Rectisol unit.(7) The major pollutant constituents of the stream are estimated to include sodium thiosulfite (11%), sodium thiocyanate (4.4%), sodium vanadate (0.7%), anthraquinone disulfonic acid (1.1%) and sodium carbonate and bicarbonate (3%). As discussed in Section 5.2.3, some SO_2 removal processes generate aqueous wastes containing high levels of dissolved salts (sodium sulfate and sulfite in the case of the Wellman-Lord process).

6.1.7 Miscellaneous Wastewaters

In addition to the sources of wastewaters discussed above, there are a number of miscellaneous wastewaters in a high Btu gasification plant whose characteristics may be unique to this type of coal conversion and related operations. These wastewaters may originate from clean-up of spills and leaks, runoff from process areas, plant cleanup and maintenance. When process wastewaters are used as cooling tower make-up, the cooling tower blowdowns are expected to contain some of the pollutants in the make-up water. Although these miscellaneous wastes are not unique to coal gasification, the wastewater characteristics will reflect the processes and chemicals used in such a plant.

6.2 WATER POLLUTION CONTROL PROCESSES

Figure 6-2 presents the wastewater treatment process modules for use in integrated high Btu gasification plants. These process modules are for oil and suspended solids removal, dissolved gases removal, dissolved/particulate organics removal, separated tar/oil and sludge treatment and dissolved inorganics removal. Each module consists of interchangeable processes which would be applicable to different ranges of wastewater concentrations and operating conditions. The processes which are reviewed in this section are listed in Table 6-4. Except for the processes for the removal of dissolved inorganics and the absorptive resin process for organics removal, data sheets were prepared for each of the processes reviewed (see Appendix E). The use of dissolved inorganics removal processes such as ion exchange, reverse osmosis and electrodialysis is not expected to be unique to high Btu gasification since at least the inorganic composition of these wastewaters would be similar to those encountered in other industries. Sorptive resins have been used in a "polishing" step for the removal of refractory organics from wastewaters after the wastewater has been treated by more conventional techniques (e.g., biological treatment). Compared to other advanced waste treatment processes such as activated carbon adsorption, sorptive resins and dissolved inorganic removal processes are also presently less developed and their potential use and cost for large-scale applications have not been evaluated.

Since no commercial SNG facility currently exists and wastewater treatment efforts at the domestic pilot plants have been very limited, very little data exist on the application of the various wastewater treatment processes to high Btu gasification wastes. All of the processes reviewed, however, have been widely used in other industries and some (e.g., biological oxidation and sludge treatment) are extensively used for the treatment of domestic wastewaters. The wastewater treatment systems at the high Btu gasification pilot plants have generally been designed to serve a "temporary" need, in some cases are "package" type systems, and in no case reflect the choice of

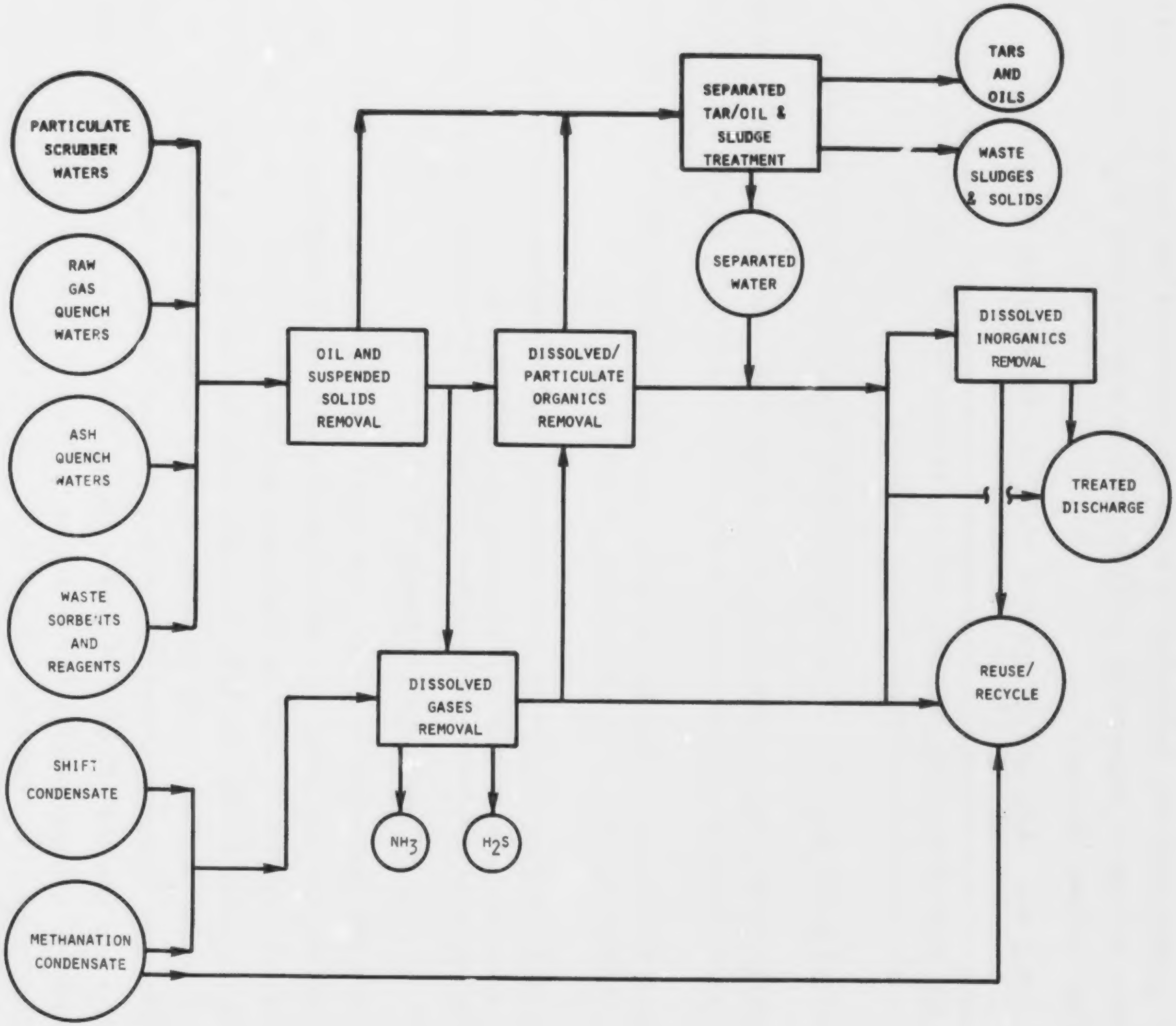
PARTICULATE SCRUBBER WATERS
RAW GAS QUENCH WATERS
ASH QUENCH WATERS
WASTE SORBENTS AND REAGENTS
SHIFT CONDENSATE
METHANATION CONDENSATE
OIL AND SUSPENDED SOLIDS REMOVAL
DISSOLVED/ PARTICULATE ORGANICS REMOVAL
DISSOLVED GASES REMOVAL
NH_3
H_2S
SEPARATED TAR/OIL & SLUDGE TREATMENT
SEPARATED WATER
TARS AND OILS
WASTE SLUDGES & SOLIDS
DISSOLVED INORGANICS REMOVAL
TREATED DISCHARGE
REUSE/ RECYCLE

Figure 6-2. Process Module for Water Pollution Control (See Figure 6-1 for sources of aqueous wastes)

treatment processes required on a commercial scale. A few of the processes (e.g., flocculation, biological treatment, and sand filtration) have, however, been used in low/medium Btu coal gasification facilities, and some data for these applications are available. A brief description of the processes listed in Table 6-4 and of evaporation ponds which have some features of all process modules reviewed follows.

TABLE 6-4. WASTEWATER TREATMENT PROCESSES REVIEWED FOR APPLICATION TO HIGH BTU GASIFICATION

Oil and Suspended Solids Removal: gravity separation (API separators), flotation, coagulation-flocculation, filtration

Dissolved Gases Removal: conventional steam stripping, Chevron WWT, Phosam-W

Dissolved/Particulate Organics Removal: Phenosolvan process, biological oxidation, chemical oxidation, activated carbon adsorption, adsorptive resins

Separated Tar/Oil and Sludge Treatment: emulsion breaking, gravity thickening, centrifugation, vacuum filtration, drying beds

Dissolved Inorganics Removal: ion exchange, reverse osmosis, electrodialysis, freezing, electrochemical treatment and distillation

6.2.1 Oil and Suspended Solids Removal

Gravity separation is usually the first step in the treatment of most wastewaters for the removal of bulk separable oil and suspended solids. "API Separators", which are gravity separators designed in accordance with the criteria suggested by the American Petroleum Institute (API), are widely used in petroleum refineries for the treatment of oily wastewaters. Gravity separation is also used following biological or chemical treatment for the removal of biological and chemical flocs. In gravity separation, the wastewater is allowed to undergo "quiescent settling" in a basin. The oil globules, which are lighter than water, float to and are collected at the surface; the settleable solids settle to the bottom and are removed as sludge. The settling basins are usually rectangular or circular in shape with "accessories" for the introduction of raw wastewater and collection of effluent, sludge and/or oil. To maximize space utilization, the settling basin design may incorporate use of inclined parallel plates/tubes, each representing a "mini basin" within which solid-liquid separation takes place. The efficiency of gravity separation depends on the wastewater characteristics and the hydraulic surface area loading of the basin. The following ranges of removal efficiencies have been reported for the API separators in refinery oil-water separation applications: 10-50% suspended solids, 50-99% free oil, 5-35% BOD, and 5-30% COD.

The wastewater treatment at the SASOL, South Africa, coal conversion plant uses (a) API separators for the treatment of the gas refining plant condensate, (b) tar/oil separators operating on the flotation principle, (c) flocculation of oily wastewaters from the Fischer-Tropsch oil production and refining units, and (d) sand filtration for the treatment of the trickling filter effluent.(5) No data are currently available on the composition of the wastewaters handled at the SASOL plant and the performance of the treatment units.

Although also applicable to and used for the separation of solids heavier than water, dissolved gas flotation is more widely used in lieu of or as a supplement to plain gravity separation for the removal of separable oils from oily wastewaters. Air is dissolved under pressure in a portion of the raw or treated wastewater or in the entire volume of the raw wastewater. In both cases, the total wastewater volume is subsequently discharged to an open basin (the flotation basin) where minute air bubbles which are released attach themselves to the oil particles and float them to the surface at a faster rise rate than would be achieved otherwise. The reported data indicate that without the addition of chemicals, flotation can result in the removal of 70-90% separable oils, 5-25% BOD, 5-20% COD and 10-40% suspended solids. In designs for the gasification of coal using the Lurgi process, the tar/oil separators operate on the flotation principle in that the reduction in pressure results in the release of dissolved gases which float oil to the surface for recovery.

Chemicals such as iron and aluminum salts and polymeric organics are often added as coagulant aids to improve the efficiency of gravity separation and flotation operations. When added to wastewaters, these chemical can destabilize colloidal particles and agglomerate fine particles into larger flocs which settle or rise at a faster rate. Particle growth is often facilitated by gentle mechanical mixing (flocculation). When used in conjunction with API separators or air flotation units, coagulation-flocculation can increase removal efficiencies and/or enable higher throughput rates.

When very high levels of oil and suspended solids removal is desired (e.g., for certain reuse applications), the conventional treatment such as gravity separation, chemical treatment or biological oxidation may be followed by filtration through a bed of inert solids such as sand, diatomaceous earth or anthracite. The suspended solids trapped in the filter are periodically removed through filter backwashing. As a polishing step for the API separator effluent, sand filtration has been reported to achieve the following removal efficiencies: 70-75% suspended solids, 52-83% free oil, 25-44% COD and 36% BOD.

6.2.2 Dissolved Gases Removal

Certain aqueous wastes (e.g., raw gas quench waters and particulate scrubber waters) contain high concentrations of dissolved gases such as ammonia and hydrogen sulfide. Some of these streams would contain smaller quantities of hydrogen cyanide and carbonyl sulfide. The removal of these gases (ammonia and hydrogen sulfide) by stripping is the most appropriate treatment step since it enables recovery of valuable by-products and significantly reduces the waste loading on downstream treatment units. Stripping of dissolved gases can be effected by contacting the wastewater with a stripping medium such as steam, flue gas, nitrogen, air and carbon dioxide. The most common stripping medium is steam and the stripping operation is usually conducted in a tower (packed or trays). Acid (for sulfide) or alkali (for ammonia) may be added to the raw wastewater to improve stripping efficiency. Steam stripping is widely used in refineries for the treatment of sour waters containing ammonia and/or hydrogen sulfide. In these applications the stripped gases are either disposed of by flaring or processed for the recovery of elemental sulfur (in a Claus plant), sulfuric acid, anhydrous or aqueous ammonia or ammonium sulfate. In many cases, the flaring of stripper off-gases is being phased out due to SO_2 and NO_x limitations. Conventional steam stripping of the refinery sour water can achieve greater than 99% removal of H_2S and up to 95% removal of NH_3. Since low molecular weight phenols are somewhat volatile, sour water stripping can also result in the partial removal of phenols (up to 70% in refinery applications).

Two patented applications of steam stripping which generate separate concentrated H_2S and NH_3 streams are the Chevron WWT and the USS Phosam W processes. In the Chevron process separate towers which operate under different pressures and temperatures are used for H_2S and NH_3 stripping. The residual H_2S contained in the product ammonia stream is removed by scrubbing the gas stream with liquid ammonia. The treated gas is then processed to convert the gaseous ammonia to anhydrous or aqueous ammonia or to ammonium sulfate. The treated wastewaters from the Chevron process can have residual H_2S and ammonia as low as 5 and 50 mg/l, respectively. The USS Phosam W process which has been designed for application to coke oven gases, features the circulation of an ammonium phosphate solution in the upper portion of the stripper to absorb the ammonia from the product stripping gases, leaving an H_2S stream containing low levels of ammonia. The ammonia rich phosphate solution is steam stripped in a separate vessel at elevated pressure and temperature, producing an ammonia rich stream which is subsequently condensed in a fractionating column to produce anhydrous ammonia. Removal efficiencies of over 99% for both H_2S and NH_3 are claimed for this process.

The Chevron WWT and USS Phosam W processes have not been employed at pilot or commercial gasification facilities to date. Conventional steam stripping with ammonium sulfate recovery, however, has been used at the SASOL gasification complex.(5) The USS Phosam W process has been incorporated into the design of the proposed ANG (North Dakota) SNG plant.(10) A recent engineering study by C. F. Braun and Company(40) comparing various stripping processes for application to coal gasification wastewaters indicate that both USS Phosam W and the Chevron WWT processes have higher capital and operating costs than conventional sour water stripping without by-product recovery. The value of the recovered ammonia, however, significantly offsets the added cost.

6.2.3 Dissolved/Particulate Organics Removal

Depending on the type and strength of a wastewater, a number of processes are available for dissolved and/or particulate organics removal. These are Phenosolvan for the extraction of phenols, biological oxidation for the removal of biodegradable organics, chemical oxidation for the destruction of refractory organics, and carbon adsorption (and adsorptive resins) for the removal of refractory organics. (Coagulation/flocculation for the removal of inorganic and organic particulate matter was discussed in Section 6.2.1.)

Phenosolvan has been developed by Lurgi Mineralöltechnik GmbH specifically for the recovery of phenols from coal gasification wastewaters. This process features solvent extraction of the wastewater using butyl acetate, isopropyl ether or light aromatic oil and subsequent recovery of crude phenol via distillation of the solvent. To minimize solvent losses to the wastewater, the "raffinate" is further treated by stripping with nitrogen gas. The process has been used for the treatment of raw gas quench water (after tar/oil separation) at several foreign Lurgi gasification facilities. The following removal efficiencies have been reported for the Phenosolvan process; monohydric phenols 99.5%, polyhydric phenols 60%, other organics 15%. The sale value of the recovered phenols has been reported to offset the capital and operating cost of the process.

In a coal gasification plant, biological oxidation would most likely be used after the bulk of the organics, reduced inorganics (e.g., H_2S, NH_3) and particulate matter have been removed by processes such as gravity separation, coagulation/flocculation, flotation, Phenosolvan and stripping. In biological oxidation, the dissolved and/or collodial organics are converted to inorganic end products and microbial cells by the action of microorganisms. The resulting biomass (sludge) is subsequently removed by gravity separation. Although biological oxidation can be conducted under anaerobic (absence of oxygen) conditions, for most applications aerobic (in the presence of oxygen) treatment is preferred because of the higher efficiency and lower costs. (Anaerobic treatment is usually used for concentrated organic wastewaters and sludges.) Biological treatment is employed widely for the treatment of industrial wastes and municipal sewage. Table 6-5 lists the most commonly used biological treatment systems including reported efficiency ranges for the removal of BOD, COD, SS, oil, phenols and sulfide from refinery wastewaters. As noted in the table, biological treatment can result in up to 90% removal of the biologically oxidizable compounds. As will be discussed in Section 6.2.6, although not classified strictly as waste stabilization ponds, evaporation and retention ponds are widely used in industry for ultimate disposal of

TABLE 6-5. EFFICIENCY OF BIOLOGICAL TREATMENT FOR PETROLEUM REFINERY EFFLUENTS*

Biological Treatment Method	Parameter[+] (% Removal)					
	BOD	COD	Suspended Solids	Oil	Phenols	$S^=$
Activated sludge	88-90	60-85	-	-	95-99+	97-100
Trickling filters	60-85	30-70	50-80	50-80	-	-
Waste stabilization pond (aerobic)	40-95	30-65	2-70	50-90	-	-
Aerated lagoons	75-95	60-85	40-65	70-90	90-99	95-100
Cooling tower oxidation	90+	90+	-	-	99.9	-
Spray Irrigation	95+	90+	99+	70-90	99.9	99+

*The ranges of values reflect differences in wastewater characteristics and system design and operating conditions.
+Approximately 70 percent of thiocyanates are removed by these processes.

raw or treated wastewaters, as tertiary treatment basins following biological treatment or as temporary storage ponds for controlled effluent discharge. Some biodegradation of organics is achieved in these ponds.

The use of pure oxygen (in place of air) in the biological treatment of wastewaters by the activated sludge process has received considerable attention in recent years and a number of pure oxygen activated sludge plants are currently handling municipal sewage and a variety of industrial wastewaters. Compared to conventional air activated sludge process, the pure oxygen process is claimed to have several advantages, including higher efficiency and loading rate, less sludge production, superior settling/thickening characteristics of the sludge, and lower overall costs. The use of the oxygen activated sludge process in coal gasification plants is especially attractive since such plants will employ on-site oxygen production and hence a source of oxygen would be available for wastewater treatment.

Although not specifically designed for biological wastewater treatment, cooling towers have been used at several refineries for biological treatment of selected waste streams. The use of cooling towers for biological treatment has also been demonstrated at the SASOL, South Africa, gasification plant Cooling towers provide ideal temperatures and surfaces for biological activity. The oxygen required by microorganisms is provided by the extensive aeration which accompanies the cooling process. In refinery applications, phenolic wastewaters have been used as cooling water make-up and more than 99% destruction of phenols has been reported. In a demonstration program at the Sasol plant, the ammonia stripper bottoms have been used as cooling tower make-up. In this program the bio-activity, foaming, fouling and corrosion which may be expected from the use of this wastewater for cooling water make-up have been evaluated and the results have been used as a basis for the design of a cooling/oxidation tower system for the proposed El Paso Burnham plant in New Mexico.(41)

Where soil, climate and hydrological conditions are favorable, biological treatment may also be accomplished by the application of partially treated wastewaters to soils. Microbiological processes in the soil can result in the degradation of most biodegradable organics and the oxidation of ammonia, sulfide, and other pollutants. In addition, physical adsorption and filtration can result in the removal and phosphorus and some metallic elements. Depending on the particular soil, the geographic location, and the rate of wastewater application, net runoff or percolation may or may not be generated. Continued application of wastewaters containing high levels of dissolved solids to soils can result in salinity and/or alkalinity buildup to the point of adversely affecting plant growth. The accumulation of certain trace elements and organics in soils may also present toxicity problems for plants or herbivores. When improperly sited, designed and operated, land application of wastewaters may present odor problems or result in the contamination of surface waters and groundwater.

Several factors which affect the applicability and performance of biological oxidation for the processing of coal gasification wastewaters are: wastewater constituent biodegradability, toxicity, pH, nutrient content and fluctuations in characteristics. As noted previously, organics in coal conversion wastewaters tend to be highly aromatic. While certain aromatic compounds such as simple phenols are readily degradable (at relatively dilute levels), the more complex and substituted phenols, polycyclic hydrocarbons and heterocyclic organics are generally less readily degradable or essentially non-biodegradable (e.g., pyridine). The biodegradability of the organics in coal conversion wastewaters is currently under study (see Section 6.5). Some of the organics (e.g., phenols), trace elements (e.g., arsenic and mercury) and inorganic anions (e.g., cyanide and thiocyanate) can be toxic to microorganisms at high concentration levels. Biological processes are generally most efficient when the pH of the wastewater is in the 6-8 range. The pH of the wastewater also affects toxicity of certain wastewater constituents. For example, the toxicity of sulfide increases with decreasing pH. Nutrients such as nitrogen (N) and phosphorus (P) compounds are necessary for microbiological growth. A BOD:N:P ratio of approximately 100:5:1 is generally necessary for the biological treatment of most industrial wastewaters. When a wastewater is deficient in nutrients, they must be added to the raw wastewater prior to biological treatment. Coal gasification wastewaters are expected to have a sufficient amount of nitrogen (in the form of ammonia) but be deficient in phosphorus content. At the SASOL, South Africa, plant where trickling filters are used for biological wastewater treatment, phosphate is added to the raw wastewater to allow efficient biological treatment.

In comparison to chemical and physical treatment processes (e.g., activated carbon adsorption, stripping, etc.), biological processes are significantly more sensitive to wide fluctuations in wastewater characteristics. When such fluctuations are anticipated (e.g., discharge from batch and transient operations), the biological treatment should be preceded by storage/mixing facilities for equalization of flow and strength. Certain biological treatment processes such as the waste stabilization pond, aerated lagoon, and completely mixed activated sludge process can tolerate limited and short duration variations in wastewater characteristics since they feature near complete mixing, or large volume and retention time.

Chemical oxidation processes using oxidants such as ozone and chlorine compounds have been used in industry for the treatment of cyanide, sulfide and thiocyanate wastes. Under proper conditions, ozonization may also effect destruction of biologically refractory organics (or their conversion into biologically degradable substances). The potential application of chemical treatment in coal gasification would probably be limited to wastewater polishing after biological treatment. Even for polishing applications, the required ozone dosage can be high and ozonization may not be cost competitive with the more conventional treatment processes. Bench scale ozone treatment of Synthane raw gas quench condensate indicates that complex organics (e.g., quinolines and indanols) and inorganics (e.g., SCN^-) can be largely removed with adequate ozone dosage.

Both granular and powdered activated carbon have been used for the treatment of industrial and municipal wastewaters. Being a physical process, carbon adsorption is unaffected by the presence of toxic constitutents in the wastewater and the fluctuations in wastewater characteristics.* Granular carbon is used in fixed or moving columnar beds with either upward or downward wastewater flow. Powdered carbon is generally mixed with the wastewater and is subsequently removed by settling and/or filtration. Because of its relatively high cost, the use of activated carbon adsorption for wastewater treatment would generally be limited to (1) removal of residual organics from the biologically treated effluents, when such removal is necessary; (2) treatment of wastewaters containing high levels of refractory organics or toxic chemicals; (3) in combination with chemical coagulation and filtration in a "physical-chemical" combination treatment scheme in lieu of biological treatment; and (4) recovery of by-products (e.g., phenols) from the wastewaters. Except when used for by-product recovery, the spent carbon is usually regenerated by thermal treatment. In polishing of biologically treated refinery and coke plant wastes, removal efficiencies of up to 80% COD, 90% TOC, and over 99% phenols have been reported for granular carbon adsorption. Similar removal efficiencies would be expected for polishing applications to coal gasification wastewaters. In some gasification processes such as Synthane, a char is produced which is subsequently gasified/combusted. The Synthane char has been shown to have adsorption properties similar to that of commercial activated carbons. Even though the char may have a much lower adsorption capacity than activated carbon, it may provide an economic source of carbon for wastewater treatment at gasification plants. The spent char can then be combusted/gasified in the normal manner.

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*When granular carbon is used in beds, some biological growth becomes established in the bed which contributes to the overall organic removal efficiency (via biodegradation). In this case the treatment efficiency would be affected by the presence of toxic chemicals or by wide fluctuations in wastewater characteristics.

Even though at the present time powdered and granular carbon is the sorbent of choice for removal of organics, other methods are being developed as alternatives to carbon or for specialized applications. One of the more promising of these methods involves the use of macroretricular polymeric adsorbents such as the Amberlite XAD-8 synthetic resin which have the ability to sorb organics without any substantial inorganic exchange capacity. The XAD-8 and similar resins have been successfully used for the decolorization of Kraft pulp bleaching effluent. The sorptive resins are usually regenerated by elution with aqueous solutions of proper pH or with organic solvents. The economics of using sorptive resins for large scale applications have not yet been demonstrated.

6.2.4 Separated Tar/Oil and Sludge Treatment

The tars and oils separated from wastewaters by gravity separation and/or flotation still contain a large amount of water (mostly in emulsified form) which may require removal prior to incineration or processing for by-product recovery. Emulsions can be "broken" by a number of methods including heating with or without chemical addition, precoat filtration, distrillation, centrifugation, and electrolytic coagulation. It is expected that some of these methods, particularly heat treatment and distillation, will find application in commercial SNG facilities for the treatment of tars and oil separated from raw gas quench waters.

Sludges generated as a result of physical, chemical or biological treatment require further treatment for concentration and volume reduction (dewatering) prior to disposal. In a coal gasification plant, sludges which may require such treatment include ash quench sludges, sludges from air pollution control systems and chemical and biosludges from wastewater treatment. Sludge dewatering is necessary to enable economic land disposal or incineration. Sludge concentration methods include gravity thickening, centrifugation, vacuum filtration, and use of filter presses and drying beds. These methods have been widely used in municipal and industrial wastewater treatment practice and considerable experience is available on them in a variety of applications. Table 6-6 presents reported data on solids concentration levels obtained by use of various sludge concentrating processes handling chemical and biological sludges. Chemicals such as lime, ferric salts and synthetic organic polymers may be added to sludges to improve dewaterability. In general, biological sludges tend to be more difficult to dewater than inorganic sludges. Biological sludges and some concentrated organic wastes can also be further concentrated by use of anaerobic digestion whereby a portion of the organic material is converted to methane, carbon dioxide and soluble by-products. In addition to the reduction in sludge volume, anaerobic digestion improves sludge dewaterability and filterability.

6.2.5 Dissolved Inorganics Removal

Several processes are under development for the removal of dissolved inorganics from wastewaters. These include ion exchange, reverse osmosis, distillation, electrodialysis, freezing, and electrochemical treatment. These processes are in varying stages of development and only the first four mentioned are given serious consideration as practical processes for large scale application to wastewater treatment. Key features of these four processes are listed in Table 6-7. As noted in the table, the ion exchange and membrane processes (reverse osmosis and electrodialysis) are subject to fouling by organics. Accordingly, the applicability of these processes for wastewater processing would be limited to effluent polishing and to wastewater containing very low levels of organics. For large applications, these processes would be energy intensive and generate waste brines requiring disposal. Of the processes listed in the table, distillation would probably be most applicable to coal gasification wastewaters for recovering water low in total dissolved solids for use as process or boiler feed water. Some or all of the heat required for wastewater distillation may be derived from various waste heat sources within a gasification facility. Some volatile substances in the wastewater may appear in the distillate and/or the condenser off-gas. Pretreatment for the removal of volatiles may thus be necessary.

6.2.6 Evaporation/Retention Ponds

Ponds for temporary or permanent retention of raw or treated wastewaters (and sludges) are widely used for disposal of industrial and municipal wastewaters. These ponds, which are referred to as "evaporation ponds," "holding basins," "lagoons," "oxidation ponds," "settling basins," etc. are usually natural or man-made earthen reservoirs into which wastewaters are discharged.

TABLE 6-6. SOLIDS CONCENTRATION OBTAINED BY VARIOUS SLUDGE CONCENTRATING PROCESSES*

Process	Type of Sludge Processed	Solids Concentration Obtained (%)
Gravity thickening	Activated sludge	5 - 8
Centrifugation	Activated sludge Lime softening sludge	6 - 11 53 - 57
Vacuum Filtration	Activated sludge	15 - 20
Drying beds	Primary and activated sludge	∿40†

*The ranges of values reflect differences in sludge properties, system design and operating conditions.

†After 15 days of drying, for one specific application.

TABLE 6-7. FEATURES OF DISSOLVED INORGANICS REMOVAL PROCESSES(42,43,44)

Process	Operating Principle	Major Existing Application	Advantages	Disadvantages
Ion Exchange	Exchange of nonobjectionable ions (e.g., H^+, OH^-) with objectionable species (e.g., Ca^{+2}, Mg^{+2}, and F^- in boiler feed water); resins are regenerated with acids, bases or salt solutions	Water softening, demineralization boiler water treatment, purification of chemicals, material recovery	Efficient and reliable process; can be automated; relatively low operating cost	Generates waste brine; most resins subject to fouling by organics
Reverse Osmosis	Use of semi-permeable membranes and application of pressure to separate water from dissolved constituents	Demineralization of brackish waters; purification of industrial chemicals and pharmaceuticals; material recovery	Removal of most wastewater components in a single operation	Generates a concentrated waste; membrane subject to fouling and degradation; relatively high energy requirements
Electrodialysis	Use of anion- and cation-permeable membranes and an electric field to effect separation of mineral ions from water	Industrial applications; pilot scale testing for wastewater treatment; demineralization of brackish waters	40-50% of the dissolved salts can be removed in a single pass	Generates a concentrated waste; membranes subject to organic fouling; limited experience with wastewater treatment
Distillation	Application of heat to evaporate water for recovery	Brackish and sea water desalinization; industrial wastewater treatment	Recovered water low in TDS	Generates a waste brine; scaling problem; high energy requirement; distillate may become contaminated with volatile substances

These ponds may be lined with impermeable materials (plastic, clay, asphalt, etc.) to prevent infiltration of the contents into surroundings. Although liners have been used for industrial waste ponds, the ability of the liner to retain its integrity over long periods of time has not been established. The retention of the wastewater in the pond provides for natural evaporation, settling of solids, biological decomposition of organics and loss of the more voltaile components of the waste. In geographic regions where annual evaporation exceeds precipitation, the ponds are generally designed to have no effluent discharge. Ponds can also be used for temporary waste storage and controlled discharge during high flows in the receiving waters. Evaporation/retention ponds require minimum maintenance and when large land areas are available, can be the most economical method for wastewater disposal. The Sasol gasification complex in South Africa uses a settling pond for polishing treatment of the total plant effluent before discharge into a river. Ponds are also used at all U.S. coal gasification pilot plants and have been featured in all proposed designs for commercial SNG facilities in the U.S. Because of solids accumulation, provisions must be made for periodic removal and disposal of solids from ponds and/or for ultimate decommissioning of ponds.

6.3 WASTEWATER MANAGEMENT AT INTEGRATED FACILITIES

The types and characteristics of the wastewaters generated in an integrated gasification plant and hence the available options for wastewater management are determined by a number of factors, the most important of which are: (a) the specific gasification, gas purification and upgrading operations employed; (b) the type of coal gasified; (c) the air pollution control and sludge/solid waste management practices used; (d) the availability and cost of raw water; (e) the climate, geographical location of the plant and land availability; and (f) the discharge regulations. Wastewater management in large industrial facilities such as integrated commercial gasification plants would provide for wastewater segregation, by-product recovery, wastewater treatment, water reuse and recycling, and good housekeeping practices. A brief review of these approaches to wastewater volume and concentration reduction follows.

6.3.1 Wastewater Segregation and By-Product Recovery

Separation of dilute and concentrated wastewaters and wastewaters of significantly different composition can often provide for more effective and economical treatment and, in some cases, enable cost-effective by-product recovery (and water reuse/recycle). Most refineries use a system of segregated sewers for separate collection, transportation and treatment of sour waters, oily waters, relatively "clean" process waters and storm runoff. Similar systems of waste segregation are used in existing coal gasification plants abroad, and are included in the designs for the proposed high Btu commercial gasification facilities in the U.S. Figure 6-3 is the schematic presentation of the wastewater management system for the proposed Burnham SNG facility. The system allows for the separation and separate treatment of the following streams: tar-rich aqueous condensates, oil-rich aqueous condensate, methanation condensate, and raw water treatment brines, sludges and ash quench water. The segregation of condensates containing large quantities of organics from other wastewaters in a gasification plant is especially important in those facilities which use processes which generate significant quantities of tars and oils, such as Lurgi. In these facilities, the waste separation enables recovery of tars and oils from relatively small wastewater volumes and reduces the load on the downstream processing units. The separated tars and oils may be incinerated on site as fuel, injected into the gasifier, used for briquetting of coal fines, or sold for chemical recovery or fuel use. In many Lurgi facilities, wastewater treatment for tars and oils is followed by the Phensolvan process for the removal of crude phenols. Recovery of tars, oils and phenols from condensates generates an effluent which can be steam stripped, alone or in combination with other plant sour waters (e.g., shift condensate), for the recovery of NH_3 and H_2S. Another example of by-product recovery at a gasification plant which would be possible through waste segregation and separate treatment is the recovery of char fines from raw gas quench condensates (e.g., in the CO_2-Acceptor process) and/or cyclone slurries (e.g., in the Hygas process) via settling and dewatering.

6.3.2 Wastewater Treatment

Effluents from by-product recovery operations and raw wastewaters not suitable for by-product recovery require treatment for the reduction of

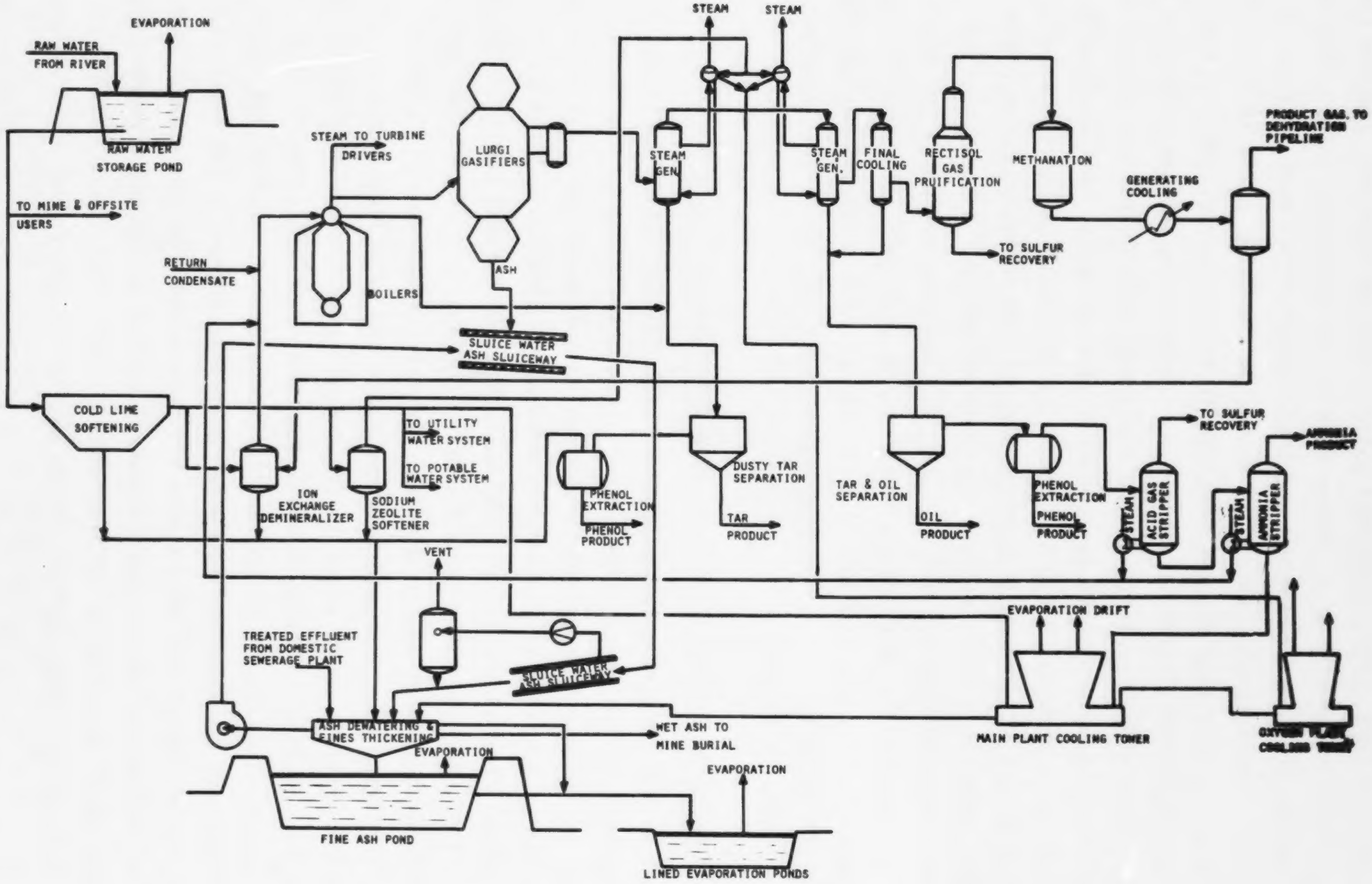
RAW WATER FROM RIVER
EVAPORATION
RAW WATER STORAGE POND
TO MINE & OFFSITE USERS
RETURN CONDENSATE
STEAM TO TURBINE DRIVERS
BOILERS
LURGI GASIFIERS
ASH
SLUICE WATER ASH SLUICEWAY
COLD LIME SOFTENING
ION EXCHANGE DEMINERALIZER
SODIUM ZEOLITE SOFTENER
TO UTILITY WATER SYSTEM
TO POTABLE WATER SYSTEM
VENT
TREATED EFFLUENT FROM DOMESTIC SEWERAGE PLANT
ASH DEWATERING & FINES THICKENING
EVAPORATION
FINE ASH POND
WET ASH TO MINE BURIAL
EVAPORATION
LINED EVAPORATION PONDS
STEAM
STEAM
STEAM GEN.
STEAM GEN.
FINAL COOLING
RECTISOL GAS PRUIFICATION
METHANATION
GENERATING COOLING
PRODUCT GAS TO DEHYDRATION PIPELINE
TO SULFUR RECOVERY
PHENOL EXTRACTION
PHENOL PRODUCT
DUSTY TAR SEPARATION
TAR PRODUCT
TAR & OIL SEPARATION
OIL PRODUCT
PHENOL EXTRACTION
PHENOL PRODUCT
TO SULFUR RECOVERY
STEAM
ACID GAS STRIPPER
STEAM
AMMONIA STRIPPER
AMMONIA PRODUCT
EVAPORATION DRIFT
MAIN PLANT COOLING TOWER
OXYGEN PLANT COOLING TOWER

Figure 6-3. Proposed El Paso Burnham Gasification Plant Water Management System(41)

organic content (BOD, COD), suspended solids, reduced inorganic species (SCN^-, $S^=$, NH_3), toxic materials (e.g., heavy metals) and dissolved salts. The various wastewater treatment processes and their capabilities were reviewed in Section 6.2. The processes which are in use at the SASOL plant in South Africa and those which have been proposed for use in the commercial SNG facilities in the United States are listed in Table 6-8. These processes are generally those which have been widely employed in the treatment of municipal and industrial wastewaters and have proved to be economical and reliable. All wastewater management plans proposed for U.S. commercial gasification facilities are aimed at achieving zero discharge to surface waters. Accordingly, these plans do not incorporate the use of advanced wastewater treatment systems such as activated carbon adsorption, ion exchange and membrane processes for the removal of potentially troublesome organics and inorganic salts and for the reduction of total dissolved solids. The use of such processes may be required if the plant effluents are to be disposed of into natural waters, applied to soils, or used for certain in-plant uses.

6.3.3 Water Reuse and Recycling and Good Housekeeping Practices

Most of the currently proposed commercial SNG facilities would be located in the western United States where water is relatively scarce and expensive. Moreover, to avoid extensive add-on wastewater treatment which may be required as a result of possibly very stringent effluent limitation guidelines which may be established in the future, the wastewater management plans for proposed SNG facilities incorporate a zero discharge concept. To achieve the goal of zero effluent discharge and to minimize raw water requirements, proposed designs for these plants provide maximum reuse and recycling of the wastewaters. Examples of multiple water usage in these facilities are: use of boiler blowdown, steam and knock-out drum condensates and ammonia stripper bottoms as cooling water make-up; use of methanation condesates for boiler feedwater; use of cooling tower blowdown and raw water softening brines as ash quench water make-up; recycling of the settled raw gas quench water to the quench tower; recycling of the settled ash quench tower blowdown to the ash transport systems; and treatment of waste brine by distillation and use of the distillate as boiler feed water. That portion of the wastewater not reused and recycled

TABLE 6-8. WASTEWATER TREATMENT PROCESSES USED AT THE SASOL PLANT AND THOSE PROPOSED FOR USE AT COMMERCIAL FACILITIES IN THE U.S.

Plant/Process	Wastewater Handled
Sasol Plant (5)	
API separation	Gas-oil refining condensate
Flocculation of oil	Petrochemical and oil refinery wastes
Trickling filtration	Combined plant and municipal wastewater
Sand filtration	Trickling filter effluent
Settling ponds	Ash quench water
Neutralization	Fischer-Tropsch acids
Drying beds	Digested biological effluent
El Paso (Burnham, New Mexico)(7,41)	
Oxidation tower (cooling tower)	Ammonia stripper bottoms
Gravity Settling	Ash quench water
Evaporation pond	Combined plant effluent
WESCO (New Mexico)(9)	
API separation	Raw gas quench water
Air flotation	API separator effluent
Biological treatment	Air flotation effluent
Gravity settling	Ash quench water
Evaporation pond	Combined effluent
Oxidation tower (cooling tower)	Biological treatment effluent
ANG (North Dakota)(10)	
Oxidation tower (cooling tower)	Stripped gas liquor
Settling pond	Ash quench water
Multi-effect evaporator (distillation)	Cooling tower blowdown
Gravity oil separator with flocculation	Runoff from plant areas

would either be disposed of with waste solids or lost as vapor in the cooling tower or from the evaporation pond. To minimize water wastage and wastewater generation, it is essential that good housekeeping and water conservation measures be incorporated in the design of integrated facilities and be observed during the operation of such plants. Such measures may include elimination of leaks, routine equipment maintenance and personnel education.

6.4 DATA GAPS AND LIMITATIONS

The data gaps and limitations relate primarily to the characteristics and treatability of wastewaters from all units in an integrated gasification facility and to the health and environmental impacts associated with such wastewaters. The data which are available have been derived from pilot plant operations in the U.S. and from commercial gasification facilities abroad which produce fuel gas or chemical feedstocks. Some of the limitations of the data from domestic pilot plants and from the operation of foreign commercial facilities were discussed in Section 5.4 in connection with air pollution control. Compared to gaseous waste streams, gasification aqueous wastes are generally characterized to a greater extent. However, most of these characterizations are in terms of major constitutents (e.g., phenols, ammonia, sulfide, etc.) and gross properties (TOC, COD, TSS, TDS, etc.); less data are available on trace elements, organics and environmental and health effects.

Waste streams from gasification plants are expected to contain some potentially hazardous substances. Very little data are currently available on the specific nature and concentration of such substances and on the hazardous characteristics of effluents containing them. Even though some toxicity data are available for some of the substances which are likely to be present in gasification plant effluents, in many cases such data are for pure substances and have been obtained in experiments with laboratory test organisms under controlled conditions. Accordingly, the data generally relate to acute toxicity and do not reflect potential effects of long-term exposure to low levels or the synergestic effects which may be associated with a very complex wastewater. The specific ecological information which appear to be lacking at the present relate to the biodegradability, bioaccumulability, and the environmental persistence of the constitutents in the gasification plant effluents and the potential for the intermedia transfer of such pollutants (e.g., contamination of soil and water environments by the leachate formed at land sites used for the disposal of gasification plant ash and sludges).

The major information gaps related to water pollution control pertain to the effectiveness of the wastewater treatment technologies discussed in Section 6.2 for the removal of specific pollutants, particularly environmentally important trace elements, organics and other substances. Although some processes such as steam stripping and biological treatment have been used for the removal of bulk volatile organics, these systems have not been adequately studied to determine the fate of specific substances and the quality of the effluent from the standpoint of composition and aquatic toxicity. Many of the advanced waste treatment processes (such as activated carbon adsorption, chemical oxidation, ion exchange, chemical precipitation and membrane processes) which would be suitable for the removal of certain troublesome organics, trace elements and inorganic ions have not been tested on coal gasification wastewaters. Some of these treatment processes may have to be employed if a very high effluent quality is dictated by discharge requirements. To date, all proposed commercial SNG facilities are to be located in areas where evaporation ponds can be used to eliminate discharge to surface waters. Evaporation ponds are probably unsuitable for use in facilities located in the eastern U.S. and hence polishing of the effluent from conventional treatment systems or use of other treatment alternatives (e.g., distillation) may be required.

The effect of various water reuse and recycling schemes on the fate of various wastewater constituents has not been investigated. For example, in cases where treated process waters are used as cooling tower make-up, the possible losses of volatile organics and inorganics originally present in the wastewater or generated as the result of biodegradation of organics to the atmosphere are not known. When process wastes (e.g., cooling tower blowdown) are used for ash quenching, some of the components of the ash may be solubilized. Certain constituents of the input water may also precipitate or adsorb on the ash/char particles and be partially or totally removed with the settled ash sludge. The alkaline environment may also induce hydrolysis and degradation of substances such as cyanide and thiocyanate. These physiochemical changes associated with ash quenching and their impact on wastewater characteristics have not been evaluated.

Because of the lack of knowledge on the effectiveness of various treatment processes for the removal of specific pollutants, the various possible sequences of unit treatment processes and reuse/recycling schemes for gasification plants cannot be evaluated at this time to determine the overall treatment efficiencies achievable and associated costs.

6.5 RELATED PROGRAMS

Many of the related programs discussed in Sections 2, 3, 4, and 5 are expected to generate data on characteristics of wastewaters produced in a coal gasification facility. One of these program is the DOE coal gasification environmental assessment programs for pilot plants which is being coordinated by the Carnegie-Mellon University (CMU). This program has generated and is expected to generate significant data on the characteristics of various wastewaters in the DOE pilot plants and on the treatability of such wastewaters. The program also includes the development and validation of protocols for effluent sampling and analysis and long-term tests of the performance characteristics of activated sludge in the processing of Hygas pilot plant quench condensate samples. In a separate DOE program, the Pittsburgh Energy Research Center (PERC) is currently conducting biotreatability studies on the Synthane process raw gas quench condensate samples from the Synthane PDU at its Pittsburgh facility. A bench-scale activated sludge unit is used for the biotreatability studies. The use of Synthane char for the adsorption of organics for the Synthane wastewaters is also being investigated by PERC. Under a joint DOE-EPA sponsorship, the DOE's Oak Ridge National Laboratory is working on development and testing of methods for chemical and biological characterization of effluents from emerging fossil fuel conversion processes.

Several on-going EPA-sponsored programs are aimed at the characterization of coal gasification effluents and evaluation of waste treatment systems for application to such effluents. These studies are conducted by the University of North Carolina at Chapel Hill, Catalytic Inc., Research Triangle Institute (RTI) and Rudarski Institute (Yugoslavia). The objectives of the University of North Carolina study are to assess the effectiveness of biological and chemical processes for the treatment of synfuel wastewaters and to determine the environmental impacts and health effects of treated effluents. Bench-scale studies are to be conducted to establish criteria for the design of large-scale units and assessment of performance. The Catalytic Inc. study involves development and testing of a methodology for "quick screening" of treatment processes for coal conversion wastewaters. The program is aimed at shortening the period of time between problem identification through Level I assessment and final recommendations for application of control technology. As discussed in Section 2.6, the RTI study is aimed primarily at gasifier effluent characterization and the correlation of gasification conditions with effluent characteristics. The Rudarski Institute program involves environmental sampling of a Lurgi gasification plant in Pristina, Yugoslavia (the Kosovo plant) - see Section 2.6.1.

7.0 SOLID WASTE MANAGEMENT

Several process and air and water pollution control modules in an integrated coal gasification plant generate solid wastes (including sludges) requiring treatment and ultimate disposal. This section reviews the sources and characteristics of such wastes and presents a discussion of various applicable solid waste treatment and disposal methods and waste management options for use in integrated facilities.

7.1 SOURCES AND CHARACTERISTICS OF SOLID WASTES

Figure 7-1 depicts the process modules generating solid wastes in an integrated coal gasification facility. There are five major categories of solid wastes: (1) chars and ashes from the gasification operation and air pollution control, (2) spent catalysts from shift conversion and methanation, (3) inorganic solids and sludges from acid gas removal and air and water pollution control (4) tar and oil sludges, and (5) biosludges from water pollution control. Of these only ash, spent catalyst and inorganic solids and sludges would be generated in almost all integrated facilities. The other types of wastes may or may not be generated in a gasification facility depending on the gasification process used and wastewater treatment processes employed. The characteristics of solid waste streams are also expected to vary from plant to plant depending on the type of coal used, specific processes employed and plant design. Since no integrated commercial SNG facility currently exists, practically no data are available on the quantities and characteristics of wastes which would be generated in large-scale facilities. The general anticipated characteristics of these and the very limited data which have been reported for pilot plant and foreign facilities are reviewed below.

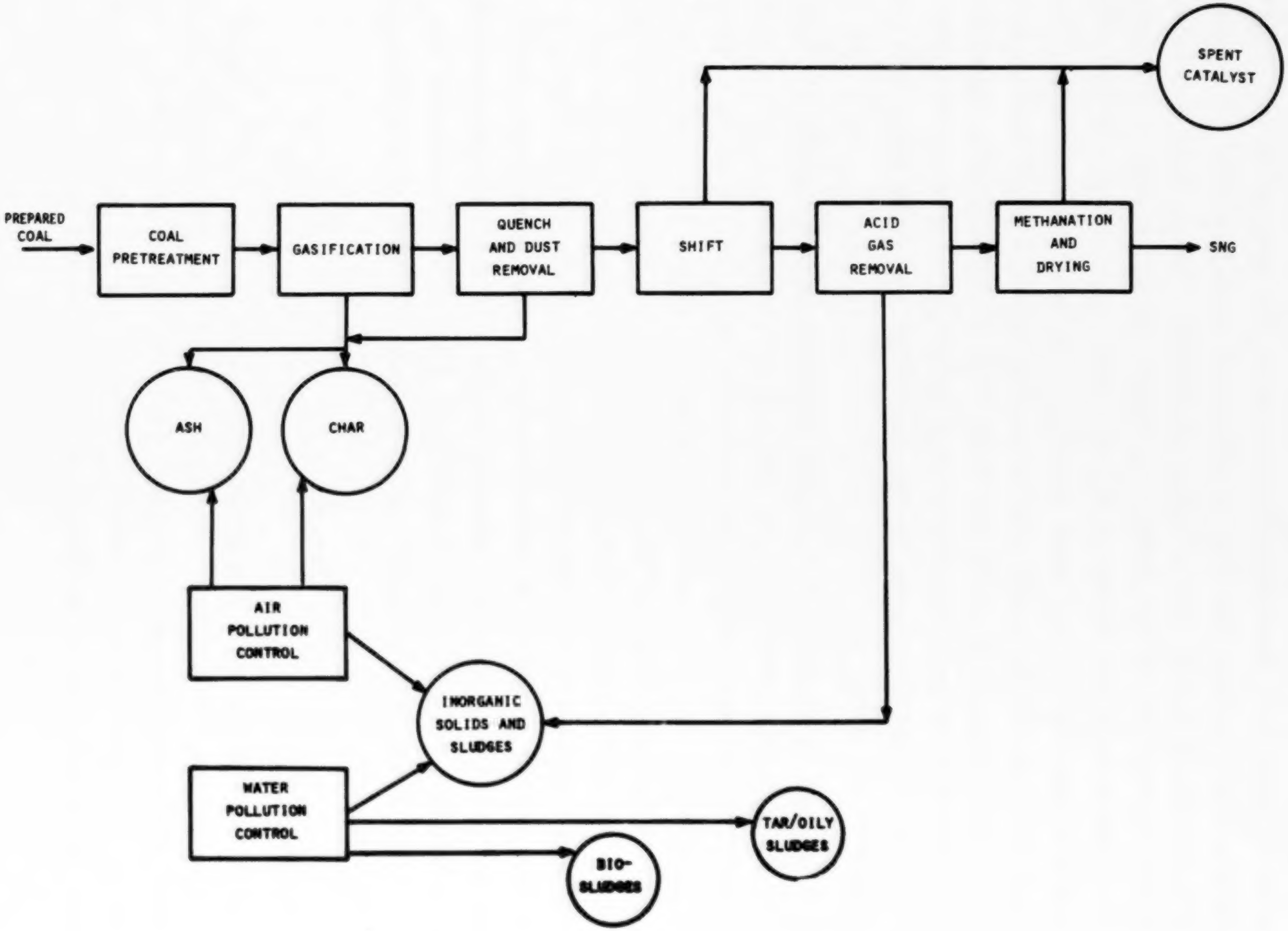
PREPARED COAL
COAL PRETREATMENT
GASIFICATION
QUENCH AND DUST REMOVAL
SHIFT
ACID GAS REMOVAL
METHANATION AND DRYING
SNG
SPENT CATALYST
ASH
CHAR
AIR POLLUTION CONTROL
INORGANIC SOLIDS AND SLUDGES
WATER POLLUTION CONTROL
TAR/OILY SLUDGES
BIO-SLUDGES

Figure 7-1. Process Modules Generating Solid Wastes in an Integrated High Btu Gasification Facility

7.1.1 Char and Ash

Processes such as Synthane, CO_2-Acceptor, Cogas and Hydrane produce a char which is gasified or combusted externally to the main gasifier. Dusts containing a significantly high char fraction are also generated in fluidized and entrained bed processes (e.g., Hygas and Bigas). These dusts are collected by cyclones (as dry ash) or by venturi scrubbers (as wet sludge). The ashes which are removed from the bottom of the gasifier (e.g., Lurgi) or the external char combustor/gasifier (e.g., Cogas gasifier) are quenched with water; the subsequent settling of the quench slurry produces a wet sludge containing the bulk of the ash. Except for their wet form, loss of some soluble components, and contamination with constitutents of the quench water make-up, the characteristics of the solids present in the ash sludge should be essentially the same as that of dry ash.

As discussed in Section 2.4.3, chars and ashes contain nearly all the inorganic constituents present in the feed coal. The reported ash and char carbon content values vary from a few percent to over 50%. Data on elemental analysis of samples of chars from Lurgi, Synthane, Hygas, Cogas and CO_2-Acceptor processes are contained in the gasification data sheets presented in Appendix A. When compared to the composition of the feed coals, the char/ash composition data indicate that the more volatile elements are partially or totally lost during gasification (see Table 2-7). The carbonaceous material in chars and ashes is primarily elemental carbon with smaller amounts of highly polymeric aromatic and heterocyclic organics. The sulfur species include pyritic, organic and sulfate sulfur. The residual nitrogen is expected to be organically bound.

7.1.2 Spent Catalysts

Catalysts used for shift conversion and methanation eventually become deactivated and require disposal. The design for the proposed commercial SNG facilities in the U.S. assumes a catalyst life of 6 months to 2 years. In addition to bulk spent catalyst, dusts containing catalyst particles may be generated during catalyst decommissioning. Such dusts are collected in the air pollution control systems used to treat the catalyst decommissioning off-gas. The shift catalysts are generally cobalt molybdate-based and the methanation catalysts are nickel-based materials supported on an inert substance such as alumina or silica. The spent catalysts from both shift conversion and methanation operations are highly sulfided and contain coal-derived trace elements (e.g., arsenic, cadmium) and elemental carbon and highly polymeric organic materials. As discussed in Chapter 4, limited shift and methanation tests have been conducted on coal-derived gases. Because of the proprietary nature of the catalysts used in these tests, very little data have been published on the detailed composition of the fresh or spent catalyst. Some data which have been released pertain to catalyst activity rather than to its composition.

7.1.3 Inorganic Solids and Sludges

Major inorganic solids and sludges include: sludges from SO_2 emission control processes, solids (e.g., spent methanation catalyst) and bottom sludges from acid gas treatment processes, sludges from chemical treatment of the wastewaters, and perhaps sulfur.

Except for the nature and levels of trace constitutents, the sludges from SO_2 emission control at gasification plants are expected to be similar to those generated in flue gas desulfurization of coal-fired utility and industrial boiler flue gas or Claus plant tail gas in refineries. The composition of a sludge from a specific application is determined primarily by the control processes used (e.g., lime/limestone slurry scrubbing vs. Chiyoda Thoroughbred 101). Some reported data on the characteristics of sludges from lime/limestone scrubbing, Chiyoda Thoroughbred 101 and magnesium oxide scrubbing are contained in the data sheets for these processes presented in Appendix D. Depending on the characteristics of the acid gas and the acid gas treatment process employed, a sorbent blowdown containing a high concentration of solids (including possibly some organics) may be produced. The treatment of this stream may generate a sludge requiring disposal. Such a sludge would most likely contain coal-derived particulate matter, sorbent, and sorbent degradation products. As currently envisioned, most SNG facilities would use zinc oxide as methanation guards. The spent guard which essentially consists of sulfided zinc oxide would constitute a solid waste stream. Chemicals such as lime or iron and aluminum salts may be used for chemical precipitation (e.g., of heavy metals) or for coagulation of particulates from process wastewaters. Such chemical treatments generate a sludge containing precipitated inorganics (e.g., ferric and aluminum hydrolysis products, other metal hydroxides, calcium carbonate, etc.) and inorganic and organic particulate matter removed from the wastewater.

Elemental sulfur would likely be produced as a by-product in commercial gasification facilities. Depending on the market conditions, sulfur purity and location of the plant, the recovered sulfur may not be marketable and hence would constitute a solid waste requiring disposal. The degree of purity of the by-product sulfur would depend on feed gas composition and the sulfur recovery process. When the feed gas contains relatively high levels of hydrocarbons, the by-product sulfur from the Claus process may contain elemental carbon. The by-product sulfur from the Stretford and Giammarco-Vetrocoke processes may be contaminated with vanadium and arsenic compounds, respectively.

7.1.4 Tar and Oil Sludges

Tar and oily sludges are produced in the treatment of oily wastewaters by gravity separation and/or flotation and in emulsion breaking. Depending on the system design and the nature of the raw wastewater and emulsions, these sludges can contain a substantial amount of water. Sludges from the API separators in petroleum refineries have been reported to contain from 7% to as much as 98% oil. The characteristics of the organic fraction of the sludge would be similar to the bulk tars and oils produced in the gasifier (see Section 2.4.2). Because tars and oils are removed from the raw gas in a quenching operation, tar and oily sludge would contain high levels of coal-derived organic and inorganic particulate matter.

7.1.5 Biosludges

When biological processes are employed for the treatment of aqueous wastes, the degradation of organics and the physical entrapment and settling of suspended particles produce a "biosludge". Sludges produced in the activated sludge and trickling filtration processes are settled in the "final" clarifiers which follow the aeration tank or the filter. In the activated sludge process a portion of the settled sludge is recycled to the aeration tank or the filter. In the activated sludge process a portion of the settled sludge is recycled to the aeration tank and the "excess" sludge is "wasted". Sludges removed from final clarifiers typically contain 2 to 5% solids with the solids generally containing 50 to 70% "volatile" matter. When lagoons and stabilization basins are used for biological treatment, the biological sludge which is produced, and the settleable matter in the raw wastewater, settle to the bottom; the degradable material in the settled sludge undergoes aerobic and/or anaerobic decomposition. Depending on the nature and quantity of the solids in the raw wastewater and the lagoon design, periodic cleaning of the lagoons to remove the settled sludge may be necessary. Certain elements (e.g., heavy metals) and refractory organics which may be present in the raw wastewater at relatively low concentration levels tend to concentrate in the biosludges. High concentrations of such substances in the sludge may eliminate certain options for sludge disposal (e.g., use as fertilizer on agricultural soils). Biosludges from refineries have been reported to contain Cr and Zn values of 540 and 200 mg/kg of dry sludge, respectively.(45) Heavy metal concentration is specially pronounced when anaerobic digestion is used for the stabilization and thickening of "primary" and "secondary" sludges.

7.2 SOLID WASTE DISPOSAL PROCESSES

Figure 7-2 identifies five solid waste management modules/processes for treatment/ultimate disposal of the major process-related solid wastes in a coal gasification plant. These are resource recovery, incineration/fuel use, soil application, land burial/landfilling, and use of evaporation/retention ponds. A number of other methods, such as ocean disposal and deep well injection, have been and are being used for the disposal of municipal and certain industrial sludges. It is very unlikely, however, that these methods would be used for the disposal of sludges from commercial SNG plants, because of environmental regulations or geographic factors. The use of evaporation/retention basins for the containment of industrial wastewaters and sludges was discussed in Section 6.2.6. The following is a brief discussion of

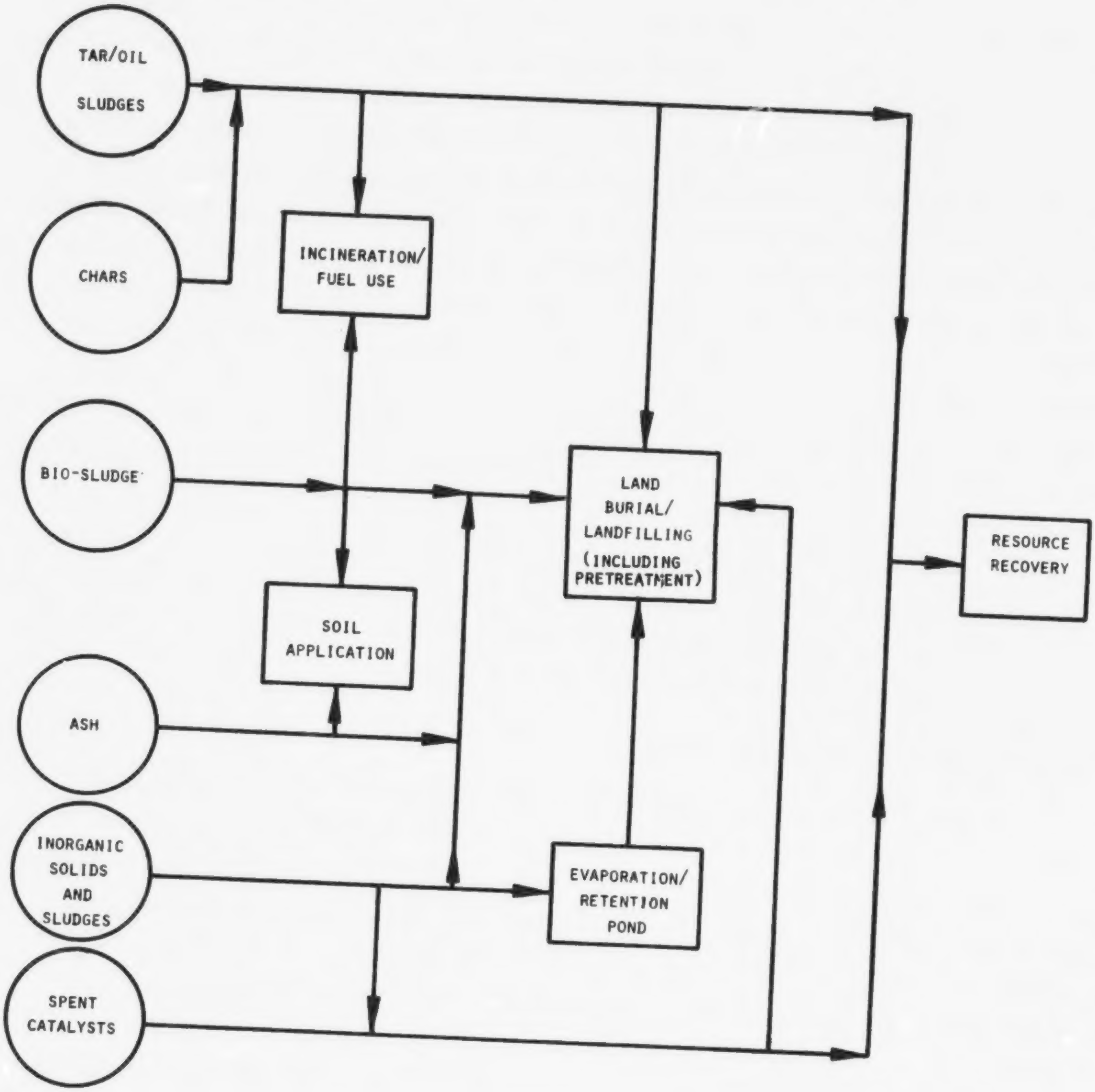
TAR/OIL SLUDGES
CHARS
BIO-SLUDGE
ASH
INORGANIC SOLIDS AND SLUDGES
SPENT CATALYSTS
INCINERATION/ FUEL USE
SOIL APPLICATION
LAND BURIAL/ LANDFILLING (INCLUDING PRETREATMENT)
EVAPORATION/ RETENTION POND
RESOURCE RECOVERY

Figure 7-2. Process Module for Solid Waste Management

resource recovery, incineration/fuel use, soil application and land burial/landfilling as they may be applied to the disposal of the various types of solid wastes in a commercial SNG facility.

7.2.1 Resource Recovery

From an environmental standpoint and when applicable, recovery of by-products from a waste or use of the waste as feedstocks in other processes would be the most desirable solid waste disposal option. In certain cases the value of the recovered material offsets the cost of the resource recovery operation. Examples of resource recovery applications for the management of waste solids and sludges in a gasification facility include: reclamation of spent catalysts and solvents; combustion/gasification of chars, tars and oils; use of ash and inert solids in the production of bricks and glass; and use of chars as "activated carbon" for wastewater treatment or as fillers in synthetic rubber.

Processing of spent catalysts (specially those containing precious metals and chromium, nickel, and zinc) for catalyst rejuvenation or recovery of metals for reuse is commonly performed in a number of industries (including the petroleum refinery), and catalyst reclamation is currently an established industry. Waste solvents can also be processed (e.g., by distillation) for solvent recovery or incinerated for heat recovery.

Chars with high carbon content (e.g., Synthane char) can be combusted directly for heat recovery or gasified. The gasification may be carried out in a separate gasifier (e.g., a Koppers-Totzek or Texaco gasifier) or in the main gasifier. Depending on the type of gasifier used, chars (as well as coal fines) may have to be briquetted before feeding into the gasifier. Tars and oils (and possibly certain process waste solvents and sludges) may also be used in the production of such briquettes.

When containing little carbon residue, ash can be utilized in a number of ways which take advantage of its inorganic, inert composition. It can be used as an ingredient of building bricks, and as mineral filler in the production of glass and ceramic products. Several processes have been developed for the use of fly ash in the production of brick. One process (developed by the U.S. Bureau of Mines) uses approximately 75% fly ash, with

25% slag and 3% sodium silicate as binder. Another process (developed by Technology Corporation) is reported to be able to use virtually any inorganic waste material to the extent of 90% to 97%; the balance is Portland cement and a proprietary "chemical accelerator." High carbon ashes (chars) can be used in asphalt, as fillers for synthetic rubber, and as a substitute for commercial activated carbon (see Sections 6.2.3 and 6.5).

Use of coal gasification ash for the production of building and construction material may be economically unattractive. Gasification plants would most likely be located away from population centers and hence from major construction activities. Furthermore, if the present supply and demand picture continues to hold true in the future, an overabundance of such ashes (e.g., from power plants) would exist which would exceed the potential demand.

7.2.2 Incineration

Carbonaceous wastes such as tars, oils, chars and dewatered biosludges can be disposed of by incineration. Depending on the water content of the feed, the combustion may be self-sustaining and also allow for heat recovery. Experience with the incineration of refinery wastes indicates that a heating value of 4000 kcal/l (30,000 Btu/gal) is necessary for self-sustaining combustion. The operation can be combined with on-site power generation or be carried out in a separate waste disposal incinerator. Incineration can reduce the waste to an ash, which because of its small volume and inertness can be more conveniently disposed of (e.g., in landfills). Incineration has proven to be very reliable and efficient and has been widely used for the disposal of a variety of industrial sludges and solids, municipal refuse and biosludges from the treatment of sanitary sewage. Nearly complete destruction of organics can be achieved in properly designed and operated incinerators. The operating temperature and the residence time in the combustion chamber are the two most important factors affecting destruction efficiency. Depending on the incinerator design and the type of waste to be incinerated, residence time and combustion chamber temperatures may vary from a few seconds to several hours and from 810°K (1000°F) to 1920°K (3000°F), respectively. Compared to land disposal methods, incineration requires very little space. Except for potential air pollution problems, which can be controlled by use of good design, afterburners, and particulate control devices, incineration is the most desirable disposal option (when resource recovery is inapplicable), especially for the destruction of hazardous organics. Major types of incinerators which are in commercial use are rotary kiln, multiple hearth furnace, fluidized bed and multiple chamber. A "data sheet" on waste incineration is presented in Appendix F.

7.2.3 Soil Application

When large land areas are available and the climate (rainfall, evaporation) and hydrogeological conditions (distance to groundwater; groundwater flow, type of soil and geological formation) are favorable, some organic and inorganic sludges may be disposed of by application to soil. The sludge is applied to the soil by "spreading" or "flooding", is disked under and worked into the top soil. The organic component of the sludge undergoes biodegradation in the soil and eventually becomes part of the soil humus. Sludge disposal by application to soils has been used for the disposal of oily sludges from production and refining of crude oil and for the disposal of biosludges from municipal sewage treatment plants. Land disposal of sludge can be used in conjunction with crop production or as part of a program for the reclamation/revegetation of lands disturbed by surface mining. Inorganic sludges and ashes can also be disposed of on land and incorporated into the top soil. Depending on the soil type, such sludges and ashes can improve soil structure, reduce acidity, provide plant nutrients, and decrease the availability and hence toxicity of certain cations. Although tar and oil sludges from petroleum refineries have been shown to be degradable when applied to soils, such sludges from coal gasification plants may be more resistant to degradation in the soil environment due to the highly aromatic nature of the organics in these sludges. As with the application of wastewaters to soils (see Section 6.2.3), sites for land disposal of sludges can present an odor problem or result in the contamination of surface waters and groundwaters, unless such sites are properly located, designed and operated.

7.2.4 Land Burial/Landfilling (Including Pretreatment)

As discussed here, land burial/landfilling includes both conventional landfilling and disposal of wastes in surface and underground mines. The general pretreatment steps for sludge dewatering and concentration were discussed in Section 6.2.4. Pretreatment involving chemical fixation and encapsulation of sludges prior to disposal in landfills is discussed in this section.

Chemical fixation (also referred to as cementation, waste passification or waste immobilization) has been used for the solidification of highly hazardous industrial wastes prior to disposal by landfilling or land burial. The objective of chemical fixation is to reduce solubility and chemical reactivity of the waste and hence reduce the potential for the contamination of ground and surface waters via leachate formation and runoff. Both organic and inorganic materials have been used as fixing agents. The fixing agents include asphalt, epoxies, tars, Portland and other lime-based cements, and proprietary formulations (e.g., in the Chem-fix process). Raw or chemically fixed sludges can also be encapsulated in plastic, metal or concrete containers or coated with self-setting resins prior to disposal. Considerable effort is currently in progress on the amenability of various wastes to chemical fixation and on the effectiveness of various chemical fixation processes to reduce the leachability of the waste. The chemical fixation processes are generally expensive and their applications limited to small-volume high-toxicity wastes. An engineering estimate for the chemical fixation of flue gas desulfurization sludge including final disposal indicates a cost of \$8 to \$13/tonne (\$9 to \$14/ton). In coal gasification, the most likely candidate waste stream for fixation would be the spent catalysts.

In conventional landfilling (i.e., use of sanitary landfills) the waste is deposited in layers on land, compacted and covered with a layer of dirt (see data sheet in Appendix F). Sanitary landfills are widely used for the disposal of municipal and industrial refuse. Co-disposal of biological wastewater treatment sludges and municipal refuse is also practiced at a number of landfills. Provided that adequate measures are taken to reduce potential for the contamination of ground and surface waters and to minimize nuisance associated with landfill operation, sanitary landfilling can be an environmentally acceptable and cost-effective method for solid waste disposal. To minimize the potential for the contamination of groundwater and surface waters, landfills must be located in areas where the subsurface formation is relatively impervious to infiltration (e.g., dense clays) and where the distance to the groundwater table is significantly large. The landfill surface area should also be properly contoured to divert surface runoff from the site. When the subsurface formations do not provide adequate barriers against leachate infiltration, the use of artificial barriers such as plastic, asphalt, concrete or clay materials for lining the landfill may be necessary. The intercepted leachate would be pumped to a surface facility for treatment. Observation wells should also be installed downstream of the landfill site (in the direction of groundwater flow) to detect leachate migration. When a gasification plant is located at some distance from the coal mine (see below) and suitable land is available, conventional landfilling would likely be employed for the disposal of bulk or chemically fixed solid wastes and sludges.

When transportation costs are not excessive, return of the coal gasification solid wastes and sludges to the coal mines would be an attractive means for the disposal of such wastes, specially when area surface mining is practiced. Disposal in surface mines would essentially be one form of landfilling where the overburden material would be used as the cover material. The operation would be subject to the same restrictions cited above for sanitary landfills. When coal is mined by deep mining, there would be a greater time delay before the waste can be deposited in the mine. In the case of deep mining, the physical operation of returning the waste to the mine would also be more difficult, requiring certain changes in mine design and operation to accommodate the space and equipment for returning the wastes. The return of ash and flue gas desulfurization sludges to the mines would have the potential benefit of reducing acid mine drainage formation. This would specially be the case in eastern mines where acid mine drainage is a major pollution problem.

7.3 SOLID WASTE MANAGEMENT AT INTEGRATED FACILITIES

In comparison with air and water pollution control operations, solid waste management options in an integrated commercial gasification facility are more limited and also more plant and site specific. The options for solid waste disposal are essentially limited to resource recovery, incineration and land disposal (soil application, landfilling, return to the mine and use of evaporation/retention ponds). Only a few of the wastes in a gasification facility (e.g., spent catalysts) lend themselves to resource recovery and it is very unlikely that this option would eliminate the bulk solid waste disposal requirement. The thermal destruction of wastes at an integrated gasification plant should be integrated with the design and operation of the gasifier and the utility boilers for on-site power generation to maximize energy recovery and minimize overall costs. The land disposal option is by far the most site-specific option and the selection of specific processes in this option would depend upon the plant location, transportation cost, hydrogeological conditions at the site and local environmental regulations. The solid waste management at an integrated plant is not an isolated problem but rather an element in the total program for pollution control. The choice of solid waste disposal methods is affected by the specific processes and options selected for air and water pollution control.

7.4 DATA GAPS AND LIMITATIONS

In comparison with aqueous and gaseous wastes for which some composition and treatability data are available for certain streams, the composition of solid wastes and hazards associated with the disposal of such wastes are essentially unknown. Some of the operations which would generate solid wastes or sludges (e.g., biooxidation of aqueous wastes) have never been used in SNG applications. Even though methanation has been tested for SNG production, little data are available on the composition of spent catalyst (see Section 7.1.2). The optimum design and operation of incinerators for the combustion of gasification solid wastes have not been established and the requirements for the control of emissions from such facilities are unknown. Although some data have been published on the composition of gasification ash, little is known about the potential leachability of such ash when discharged on land or in landfills.

7.5 RELATED PROGRAMS

Many of the related programs discussed in connection with gasification, gas purification and upgrading and air and water pollution control are expected to generate some data on the characteristics of solid wastes in a coal gasification plant. The most relevant of these programs are (a) an EPA-funded program for the characterization of coal and coal residue, conducted by the Illinois State Geological Survey (see Section 2.6.1); (b) DOE's coal gasification environmental assessment program coordinated by Carnegie-Mellon University (see Section 2.6.2); and (c) the EPA-DOE program conducted by Oak Ridge National Laboratory for the chemical and biological characterization of by-products and aqueous and solid wastes from coal conversion processes (see Sections 2.6.3 and 6.5).

8.0 SUMMARY OF DATA GAPS AND LIMITATIONS AND RELATED PROGRAMS

As noted in Section 1.0, the first step in the present program for the assessment of the high Btu coal gasification has consisted of collection and detailed analysis of the available relevant information in order to identify (a) gaps in and limitations of the existing data, (b) additional data required for the preparation of detailed environmental impact assessments and (c) on-going and planned programs which might generate some of the needed data. The data collected on various processes and control technologies which may be potentially used in an integrated gasification facility are presented in Volumes II and III (Appendices) in "data sheet" format and were discussed in the preceding chapters in this volume. This section summarizes the major gaps identified in the available data and the most relevant on-going or planned programs which are expected to generate some of the needed data.

8.1 MAJOR FACTORS RESPONSIBLE FOR DATA GAPS AND LIMITATIONS

The limitations of the available data stem from a number of factors, most important of which are the following:

- Even though a number of gasification pilot plants have been in operation in the United States, the operation of these pilot plants has been aimed primarily at the development of the gasification process with little emphasis on process and waste stream characterization from an environmental standpoint. The test and evaluation of the developmental processes have not generally included process optimization to minimize pollutant generation or to assess control technology needs. Even though the final design and operating practices at commercial facilities and the type of coal which would be used in such facilities may be different than those represented by the pilot plant operations, the pilot plant operations currently provide the best and the only means of acquiring meaningful environmental data in the United States.

- Except for the Lurgi (dry ash) process which has been used commercially abroad, the high Btu gasification processes are in the pilot plant or bench-scale development stage. The commercial Lurgi facilities do not incorporate the downstream processes which would be employed in a commercial SNG plant.

- Commercial gasification facilities which are in operation in foreign countries do not generally incorporate design and operating features which would likely be employed in an SNG facility in the U.S. to minimize waste generation and to control discharge. Moreover, the coals used at these facilities differ from those which will be employed at commercial SNG plants in the U.S.

- Although many of the unit operations for gas processing and pollution control which may have applications in commercial SNG production have been tested or used commercially in other industries, their performance in SNG service has often not been evaluated.

- Some of the gasification, gas processing and pollution control processes have been or are being developed by private industry. Much of the data which may exist for these processes are considered proprietary and hence not publicly available.

- For many of the unit operations where some discharge stream characterization data are available, such data are not comprehensive in that not all streams are addressed and not all potential pollutants and toxiciological and ecological properties are defined.

- Even though there has been a long-standing interest in the conversion of coal to liquid and gaseous fuels and a number of coal conversion facilities have been in operation for some time in other countries, it is only very recently that there has been a very strong interest in assessing the environmental aspects of the coal conversion technologies. This interest stems primarily from two factors: (1) a growing public concern for environmental protection as reflected in enactment of environmental laws, and (2) an increased sense of urgency for developing a synthetic fuels industry.

8.2 SPECIFIC DATA GAPS AND LIMITATIONS

Because of the reasons stated above, it is not very surprising to find a large number of gaps and limitations in the available data. In general, these data gaps and limitations fall into two categories: (1) total nonexistence or unavailability of the data, and (2) data which are available lack comprehensiveness or have been obtained under conditions significantly different than those anticipated in an integrated commercial SNG plant in the U.S. Examples of data gaps in the first category are the lack of detailed characteristics data on emissions associated with decommissioning of spent methanation catalyst, on combined effluent in an SNG plant, and on sludges resulting from the treatment of such effluent or from the treatment of tar and oily condensates. Since no integrated SNG facility currently exists, this type of data is not available from actual operation. Even though environmental characteristics of SNG plant wastes can be estimated through engineering studies, to date only a limited number of such studies have been conducted. In the case of emissions from catalyst decommissioning, even though some data might exist, such data are not publicly available due to proprietary considerations.

Examples of the second category of data gaps and limitations are the lack of trace element and organics data and toxicological and ecological characteristics data for various waste streams in a gasification plant and data on the performance of various control systems in SNG service. In comparison with the very limited amount of data which are available on most gasification processes, considerable data are available on the characteristics of aqueous wastes from the Hygas and dry ash Lurgi processes. These data, however, do not cover organic and trace element constituents, bioassay information, waste treatability and hazardous characteristics such as biodegradability, health effects and potential for bioaccumulation and environmental persistence. For the Stretford process, which has been used in refinery and by-product coke applications for H_2S removal from acid gases containing relatively low levels of CO_2, limited commercial experience exists with acid gases containing high levels of CO_2 which would be encountered in an SNG plant. With the exception of a few pollution control processes (e.g., flaring for hydrocarbon and H_2S control, venturi scrubbing for particulate removal, Phenosolvan for recovery of phenols from wastewaters, sour water stripping for NH_3/H_2S removal and trickling filters for biological treatment), the various air, water and solid waste control processes which would be potentially employed at commercial facilities have not been used in coal gasification applications. Even for the few processes which have been used for coal gasification, very little data are available on the characteristics of the treated streams and on the performance and costs of these applications. Tables 8-1 and 8-2 list the major data gaps relating to coal gasification and gas purification and upgrading, respectively.

The first category of data gaps can only partially be filled (e.g., through engineering analysis) at the present time since SNG facilities do not exist and the existing pilot plants do not incorporate all the units or design features of a large scale facility. Many of the gaps in the second category,

TABLE 8-1. SUMMARY OF DATA GAPS AND LIMITATIONS FOR THE GASIFICATION OPERATION

Gasification Process	Discharge Stream								Comments
	Pretreatment Off-gas	Pretreatment Scrubbing Water	Raw Product Gas	Ash/Char	Quench Condensate	Quenched Product Gas	Tars/Oils	Lockhopper Vent Gases	
Dry Ash Lurgi	Not applicable	Not applicable	No data available	Considerable data available on composition for foreign and 4 U.S. coals; no data on leachability, adsorption characteristics, and toxicity	Considerable data available on gross properties for 4 U.S. coals; little or no composition data for trace elements and organics	Considerable data on major constituents for 4 U.S. coals and some foreign coals; limited data on minor gas constituents; no data on trace organics and trace elements	Some data available on physical properties and elemental composition; little data on specific organic constituents, trace elements and ash components; no toxicity data	No composition data available	Available data are from commercial-scale gasifiers. Much of the data from testing of 4 U.S. coals at Westfield, Scotland
Slagging Gasifier	Not applicable	Not applicable	No data available	Limited data on major and minor constituents, no data on leachability, adsorption characteristics and toxicity	Limited data on major constituents and parameters, no data on trace elements and organics	Limited data on major constituents, no data on trace elements and organics	Some elemental composition data; no data on specific organics, trace elements and toxicity	No data available	Most of the data from small pilot plant gasifier at Grand Forks Energy Research Center
Hygas	No actual composition data available for environmentally important species	Considerable data on major constituents and parameters; no data on trace elements, organics and toxicity	Very limited major component data available; no data on particulates, minor gases, trace elements or organics	Limited major and minor element composition data for both gasifier ash and product gas cyclone solids, no data on leachability, adsorption characteristics, trace organics and toxicity	Same as for pretreatment scrubbing water	Same as raw product gas	Relatively comprehensive organics characterization data on few selected oil samples in short runs, no toxicity data	Not applicable	Available environmental data relate to the pilot plant operation which uses the steam oxygen version of the process
Cogas	Requirement for pretreatment not known	No data available	No data available	Some major and minor element composition data available for COED char; no data available for gasifier ash	Very limited data for major elements, phenols and dissolved and suspended solids, no other data available	Limited major component data available, no data on particles, minor gases, trace elements or organics	Same as Lurgi above	Not applicable	Features of quench system for product gas/oil/water separation not known. COED & COGAS pilot plants have not been operated as an integrated unit
CO_2-Acceptor	Not applicable	Not applicable	No data available	Limited major and minor element composition data for gasifier char, regenerator ash, and spent acceptor; leachability, adsorption characteristics, trace elements and toxicity not known for these solids	Considerable data on major constituents and parameters; little data on trace elements, organics, and toxicity	Limited data on major components. Very little data on minor components. No data on trace elements or organics	Not applicable	No data available	Limited major components/parameters and trace element data are available for char combustion, flue gas and associated quench waters
Synthane	Caking coals have not been tested to date	Caking coals have not been tested to date	No data available	Limited data on major and minor element composition available from PDU operation; no data on organics, leachability, or toxicity	Limited data available on major constituents and parameters, and trace elements, no data on trace organics and toxicity	Limited data on major components available, very little data on minor gas components and organics	Relatively comprehensive organics characterization data available for a few selected tar samples from PDU operation; no toxicity data	No data available	Most of the data for Synthane is for PDU operation; pilot plant has achieved only short periods of steady state operation
Bigas	Not applicable	Not applicable	No data available	No data available	No data available	Very limited major component data available; no data on trace elements, gases, and organics	Not applicable	Not applicable	The limited data available for Bigas operation are for bench scale unit. Pilot plant has not attained steady state operation to date
Hydrane (Hydrogasification)	Pretreatment requirements not known	No data available	No data available	No data available	No data available	Same as Bigas	No data available	Not applicable	Limited available data derived from bench scale unit. Char gasification has not been tested

TABLE 8-2. SUMMARY OF DATA GAPS AND LIMITATIONS FOR GAS PURIFICATION AND UPGRADING OPERATIONS

Module/Process	Process/Discharge Stream					Comments
	Feed Gas	Treated Gas	Concentrated Acid Gas	Aqueous Condensate/Blowdowns	Solid Wastes/ Sludges/By-Products	
Shift Conversion	**Major components well known. Additional data needed for COS, CS_2, NH_3, HCN, trace elements, organics and particulates**	Same as feed gas	Not applicable	No data available	No data available for spent catalysts	The effect of catalyst on minor gas constituents not known
Acid Gas Removal						
• Hot gas H_2S removal	Same as above	Very limited data for major components and H_2S. No other data available	No data available	Not applicable	No data available	Hot gas H_2S removal is in very early development stage
• Physical solvents	Same as above	Considerable data on H_2S and CO_2 content in various applications. Limited data available for trace gases and organics. No trace element data	Same as treated gas	No data available	No data available	Only the Rectisol process has been employed in coal gasification applications to date
• Chemical solvents (amines)	Same as above	Same as above	Same as treated gas	No data available	No data available	Only the DGA process has been tested in coal gasification service
• Carbonate solvents	Same as above	Considerable data on H_2S and CO_2 content in various applications. Limited data for trace gases	Same as treated gas	Limited data are available on composition of Benfield solution after prolonged service in coal gasification. Quantities of and trace constituents in blowdown (if any) are not known	No data available	The Benfield process has been commercially used for acid gas removal in coal gasification service
• Mixed solvents	Same as above	Limited data on H_2S and CO_2. No data on trace gases	Same as treated gas	No data available	No data available	A Sulfinol unit has been used in a gasification facility in Turkey, but no operating data are available
• Redox processes	Same as above	Limited data on H_2S and CO_2. Very little data on trace gases	Same as treated gas	No actual operating data available	No actual operating data available	Available data for the Stretford process are derived mainly from conceptual designs rather than actual operation. Neither the Stretford nor the Giammarco-Vetrocoke process has been used in coal gasification
Methanation Guards	Same as above	Limited data available on total sulfur and major components. No data available on trace gases	Not applicable	No data available. (Not applicable for some processes.)	No data available	Methanation guards have not been employed in coal gasification applications to date
Methanation	Major constituents well known; no data on trace sulfur and nitrogen compounds	Major constituents well known. Little known about metal carbonyls which may be formed	Not applicable	No data available; expected to be very clean condensate	Limited data on nickel and sulfur content and physical properties of spent catalyst. No data on trace elements, organics or toxicity	Only fixed bed methanation is sufficiently well tested for SNG production at present. Essentially nothing is known about emissions resulting from catalyst decommissioning

however, can be and should be filled through multimedia environmental sampling and analysis of the process/discharge streams at pilot plants and foreign gasification facilities, through bench-scale studies and through engineering analysis. Even though some of the unit operations and conditions in the gasification pilot plants are not scalable to or representative of commercial facilities, and in the absence of such commercial facilities, sampling at the pilot plants represents the best and the only means of acquiring meaningful data on process and waste stream characteristics and on the performance of various processes. Such sampling and analysis programs, coupled with related engineering studies and bench-scale testing, can provide valuable and timely input to the evolution of the SNG industry and would assure that (1) environmental considerations are included in the selection of processes, equipment and waste management options for commercial SNG plants and (2) the drafting of New Source Performance Standards for SNG facilities are based on sound technical and engineering data. Several programs are currently under way or planned which involve testing/sampling at pilot plants, bench scale units, or foreign commercial facilities. The more important of these and related engineering studies are summarized below.

8.3 RELATED PROGRAMS

Major programs which are expected to generate some of the data needed for high Btu gasification environmental assessment fall into three categories: EPA-sponsored programs, DOE-sponsored programs, and miscellaneous programs. The EPA- and DOE-sponsored programs are listed in Tables 8-3 and 8-4, respectively. Very limited data are available on the programs in the miscellaneous category which are primarily carried out under private funding. Of the EPA programs, the one most directly related to the high Btu gasification is the TRW environmental assessment effort for which the preparation of this document has been the first step. As mentioned in Section 1.0, the TRW program includes the acquisition of data through sampling and analysis of process/waste streams at selected gasification facilities. In this connection, TRW contacted DOE, private process developers in the U.S., and commercial facilities overseas. Initial steps have been taken to develop test programs for these facilities. TRW has also been in contact with DOE to obtain unpublished environmental data and to obtain access to DOE facilities for sampling and

TABLE 8-3. SUMMARY OF SOME EPA-SPONSORED PROGRAMS

Project Title	Contractor	Objective	Status and Future Activities
Environmental Assessment of High Btu Gasification	TRW, Inc. Redondo Beach, Ca.	Environmental assessment of high Btu gasification, including identification of control technology needs.	Data base document prepared. Preparations for sampling/analyses at domestic and foreign facilities underway.
Environmental Assessment of Low/Medium Btu Gasification	Radian Corporation Austin, Texas	Environmental assessment of low/medium Btu gasification, its utilization, and definition of control technology needs.	Data base document has been prepared; Radian is providing technical assistance during environmental testing currently being conducted at 4 gasification facilities.
Environmental Assessment of Coal Liquefaction	Hittman Associates Columbia, Md.	Environmental assessment of coal liquefaction technology and definition of control technology needs.	Data base document prepared, summarizing data on 14 liquefaction processes and discussing four processes (SRC, H-Coal, Exxon Donor Solvent and Synthoil) more thoroughly.
Control Technology for Products/By-Products	Catalytic, Inc. Philadelphia, Pa.	Development and testing of methodology for "quick-screening" of treatment processes for synfuels wastewaters.	Preliminary evaluation of mobile test facility housing bench-scale equipment for studying coal conversion systems completed.
Pollutants Identification from a Bench-Scale Unit	Research Triangle Institute Research Triangle Park No. Carolina	Semi-quantitative determination of chemical species in gasification effluents as a function of gasification conditions and kinetic data on rates of species formation.	Lab-scale gasification reactor designed and operated with coke and Ill. No. 6 bituminous coal. Sampling train for gaseous and liquid samples, and analytical techniques under development.
Waste Stream Disposal and Utilization	Pullman-Kellogg Houston, Texas	Identification and assessment of control technologies for waste utilization and disposal associated with fuel conversion technologies.	As a first step, general definition of all potential environmental problems associated with synfuels processes has been performed, and information on the composition and quantity of typical discharge streams gathered. Waste treatment technologies currently being studied.
Characterization of Coal and Coal Residues	Illinois State Geological Survey Urbana, Ill.	Characterization of the chemical, physical and mineral properties of coals, coal by-products and wastes; investigation of the effects of pyrolysis on trace element distribution and providing data on solubilities and toxicities of species in coal wastes.	Data generated on chemical form of trace elements in coal, char; pyrolysis studies conducted; toxicity and bioassay studies of coal solid wastes conducted. Additional pyrolysis, toxicity and leaching studies planned.
Water Treating Bench Scale Unit	University of No. Carolina Chapel Hill, No. Carolina	Assessment of the effectiveness of various biological/chemical treatment processes, and determination of the environmental impacts and health effects of treated effluents.	Bench-scale studies being initiated in order to establish criteria for design of large-scale biological/chemical treatment units. Activated sludge reactors recently tested.
Acid Gas Cleaning Bench Scale Unit	No. Carolina State Univ. Raleigh, No. Carolina	Construction and operation of a general purpose coal gasification/gas cleaning facility.	Program is in initial stages. Evaluation of 4 absorption solvents for acid gas removal processes (e.g., Rectisol, Benfield, MEA and Selexol) to be conducted.
General Support	Cameron Engineers, Inc. Denver, Colo.	Preparation of "Multi-media Environmental Control Engineering Handbook."	Approximately 35 device-specific data sheets completed.
Control Technology for Particulates and Tar Emissions	Hydrocarbon Research, Inc. Morristown, N. J.	Determination of ultimate fate of particulates and tars, estimation of costs of alternate control technologies, and development of a prioritization R&D plan for particulates and tar control technology.	Literature search in progress to characterize particulates and tar emissions from various coal converters.

TABLE 8-4. SUMMARY OF SOME DOE-SPONSORED PROGRAMS

Contractor	Objective	Status and Future Activities
Carnegie-Mellon University Pittsburgh, Pa.	To provide overall coordination and evaluation for DOE pilot plant environmental assessment program; to develop sampling and analysis protocols.	Ten specific program tasks, including development/validation of sampling and analytical procedures, and studies on treatability of process effluents, are under way.
Pilot Plants Environmental Sampling and Analysis Programs		
• Hygas, Institute of Gas Technology	Sampling and analyses of various process/waste streams; development of sampling and analysis protocols.	Sampling and analysis performed since mid-1976; extensive data generated. Sampling and analysis planned for raw product gas. Batch and continuous leaching tests to be performed on Hygas char. Additional data to be generated for high carbon conversion. Testing to continue through 1978.
• CO$_2$-Acceptor, Radian Corporation	Sampling and analysis of various process/waste streams.	Comprehensive test program prepared and executed prior to shutdown in 1977. Numerous gas phase and wastewater analyses performed. Results soon to be published.
• Synthane, Pittsburgh Energy Research Center	Sampling and analysis of various process/waste streams.	A process/waste stream sampling and analysis program is under way. Performance of Benfield and Stretford process units to be assessed.
• Slagging gasifier, Grand Forks Energy Research Center and Sterns-Roger, Inc.	Sampling and analysis of various process/waste streams.	Analyses performed and results reported on the composition of product gases, condensates and slag produced with lignite feed. Similar data to be collected for other coals.
• Bigas, Phillips Petroleum and Penn Environmental Consultants	Sampling and analysis of various process/waste streams.	Limited sampling/analysis of selected Bigas condensates performed. Testing under steady state conditions has been hampered by operating difficulties with the gasifier.
Pittsburgh Energy Research Center Pittsburgh, Pa.	To determine biotreatability of Synthane wastewaters.	A bench-scale activated sludge unit has been constructed and operated. Use of Synthane process char as adsorbent for wastewater organics also being investigated. Testing to continue.
Oak Ridge National Laboratory, Oak Ridge, Tenn.	To determine and assess potential environmental/health problems associated with coal conversion.	A number of studies have been proposed and some implemented relating to industrial hygiene/safety, epidemiological studies, and pollutant monitoring techniques. Program to characterize trace element and organic composition of solid wastes at a Lurgi facility under way. Also, program for the development of short-term genetic bioassay for characterization of complex effluents and chemical mutagen identification is under way.
Argonne National Laboratory Argonne, Illinois	To analyze trace organics at pilot plants using gc/ms; also, to perform biological characterization of various sample fractions from pilot plants.	Programs recently initiated. Effluents from high and low/medium Btu gasification operations to be studied, beginning with condensates from the Hygas pilot plant.
Battelle-Pacific Northwest Laboratories, Richmond, Va.	To characterize products/wastes from synfuels processes.	Limited sampling and analysis conducted at CO$_2$-Acceptor pilot plant; effluents from LERC in-situ coal gasification facility analyzed. Data soon to be made public.
C. F. Braun & Co. Alhambra, Ca.	To serve as evaluation contractor for joint DOE-AGA gasification assessment program.	A number of engineering studies are being conducted, including programs on management of sulfur emissions in commercial gasification facilities.
Consortium of companies headed by Conoco, Inc. in cooperation with British Gas Corporation	Slagging gasifier testing at Westfield, Scotland. Results of tests to serve as basis for the design of a slagging Lurgi gasification demonstration plant in the U.S.	The 3-year program has involved modification of a Lurgi gasifier and its operation under slagging conditions. Ohio No. 9 and Pittsburgh No. 8 coals have been tested.

analysis. A number of unpublished documents have already been received from DOE and DOE has agreed to have TRW review and comment upon its sampling and analysis programs for Hygas and Synthane pilot plants and to provide TRW with selected samples from these two pilot plants.

DOE synthetic fuel pilot and demonstration programs include sampling and analysis at various facilities, bench-scale studies of process and environmental data acquisition, and related environmental engineering studies.

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